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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	**DOCKET NO. E-01933A-15-0322**
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	**DOCKET NO. E-01933A-15-0239**

Arizona Corporation Commission
DOCKETED
JUN 24 2016
DOCKETED BY

NOTICE OF FILING STAFF'S DIRECT TESTIMONY REGARDING RATE DESIGN AND COST OF SERVICE

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission") hereby submits the Direct Testimony regarding Rate Design and Cost of Service of Staff witnesses Howard Solganick, Michael J. McGarry, Robert G. Gray, Matt Connolly, and Eric M. Van Epps.

A confidential version of Howard Solganick's Direct Testimony regarding Rate Design and Cost of Service is being provided under seal to the Commissioners, their Policy Advisors, the assigned Administrative Law Judge, the Residential Utility Consumer Office and Tucson Electric Power Company ("Company"). The Company will provide the confidential version to those other parties with whom it has entered into a Protective Agreement in this matter.

RESPECTFULLY SUBMITTED this 24th day of June, 2016.

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BEFORE THE ARIZONA CORPORATION COMMISSION

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Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT

RATE DESIGN TESTIMONY

OF

HOWARD SOLGANICK

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 24, 2016

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EXHIBITS

EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-15-0322 AND E-01933A-15-0239

Mr. Solganick's direct rate design testimony reviews the Tucson Electric Power Company ("TEP" or "Company") proposal for cost of service, revenue allocation, rate design, and modifications to the Lost Fixed Cost Recovery mechanism ("LFCR").

Taking a multi-case view, the Arizona Corporation Commission Utilities Division Staff ("Staff") recommends that the long-term (but not this case) rate design should focus on a three-part rate (customer, demand and energy) including time-of-use ("TOU") to better and more accurately relate rates to underlying costs. For informational and educational purposes only, Staff proposes the Company provide all residential and small general service customers with their monthly On-Peak and Off-Peak demands. Staff recommends that the Company offer customers access to their usage information through a website or other means of access. The Company should also develop an education program to help customers understand their usage information and how customers can manage their usage and change the size of their bills.

Mr. Solganick evaluates TEP's Class Cost of Service Study ("CCoSS")and places its results into perspective, and Staff recommends that it be used as a guide to revenue allocation and a source of unit cost data for rate design.

Mr. Solganick provides the Staff recommendation for the allocation of Staff's recommended rate increase among the six major rate classes. This recommendation is tempered by the concept of gradualism due to the changes in rate base and changes in TEP's proposed cost allocation methodology for generation plant along with the recognition of the purchase of a share of Gila River Unit No. 3.

Based on a review of TEP's application, responses to Staff data requests and consistent with Staff's long-term rate design plan, Mr. Solganick provides recommendations for the rate design for each of TEP's rate classes along with Lifeline, distributed generation, service fees, the Buy-Through provision, Automated Metering Infrastructure ("AMI") Opt-Out customers and the Economic Development proposal of TEP. The impact of Staff's proposed rate design is provided for residential ("RES") and small general service ("SGS") customers.

Staff recommends that the Commission accept TEP's proposal to eliminate the Fixed Charge Option from the LFCR mechanism. Staff recommends that the Commission reject the Company's other LFCR proposals.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc. ("Blue Ridge").

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies:

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Q. What is the purpose of your rate design testimony?

A. My testimony provides Staff's long-term plan for rate design, analyzes the Class Cost of Service Study ("CCoSS"), Staff's recommended allocation of the revenue increase proposed by Staff, and recommends how the increased revenue should be implemented within the

Company's various existing and proposed rates. I also present Staff's recommendations to address Lifeline rates, distributed generation ("DG"), Service Fee charges, Buy-Through provision, Automated Metering Infrastructure ("AMI") Opt-Out and economic development. Finally, I present Staff's recommendations for the existing Lost Fixed Cost Recovery ("LFCR") mechanism.

Q. Are you the only Staff witness providing direct rate design testimony in this docket?

A. No. The following people will also be providing direct rate design testimony.

- Mr. Michael McGarry will be addressing the proposed modifications to the Purchase Power and Fuel Adjustment Clause.
- Mr. Bob Gray will be addressing the expansion of the TEP-Owned Rooftop Solar program and the proposed Residential Community Solar program.
- Mr. Matt Connolly will be addressing the proposed residential prepay metering program and several compliance requirements.
- Mr. Eric Van Epps will be addressing the proposed changes to the Environmental Compliance Adjustor, Demand Side Management Surcharge and the Renewable Energy Standard and Tariff Surcharge.

DIRECT TESTIMONY

Q. Please summarize Staff's positions?

A. Staff recommends:

Long-Term Rate Design Plan

Over the long term, rates should be based on costs and recognize the concepts of customer, demand and energy including time-of-use ("TOU"). When changes are made, gradualism should be recognized. The long-term plan is placed into the context of evolving metering and customer information capabilities.

Class Cost of Service Study

The purposes of a CCoSS are discussed along with the changes in the Company's CCoSS including a new production cost methodology.

Revenue Allocation

Staff recommends a revenue allocation among the customer classes based on moving all classes to cost of service but recognizing that gradualism is necessary due to the effects of a new production cost methodology and the Company's inclusion into rate base of a portion of the new Gila River Unit No. 3.

Rate Design

Staff recommends rate designs for each rate schedule and, consistent with the long-term rate design plan, recommends the implementation of optional Three Part-TOU rates for residential and small general service rates customers and a requirement that the Company begin to provide demand information for non-demand rate RES and SGS customers. Staff also highlights areas where the Company should provide further information and justification for its proposals.

Staff highlights that due to the implementation of the proposed Medium General Service ("MGS") rate class the Commission should keep the rate design portion of the case open to resolve unanticipated customer rate impacts.

Miscellaneous Items

- Lifeline – Staff recommends that the level of this discount not be reduced and that the transition of these customers to standard residential rates with the addition of a single discount for Lifeline be continued.

- Distributed Generation – Staff notes that Commission Docket No. E-00000J-14-0023, which is intended to examine the value and cost of DG, will continue to provide useful information to the parties in this rate case. Therefore, at this time, Staff does not propose any changes to the existing net metering tariff or waivers of the net metering rules but it may update its position in its Surrebuttal testimony or later at the hearing in this case.

- Service Fee Charges – Staff analyzed the Company's proposals and recommends which fees should apply to Opt-Out customers.

- Buy-Through – Staff looks forward to the input of other parties and does not object to this mechanism if there are no adverse impacts and no costs to other customers.

- AMI Opt-Out – Staff recommends that a non-transmitting solid-state meter be used to accumulate information needed for billing, customer service and customer education along with recommended charges for the installation of the meter and monthly meter reading.

- Economic Development – Staff supports the establishment of the program but does not support any request for lost revenues.

LFCR

Based on a review of the Company's application, supporting testimony, and responses to data requests, Staff recommends that the Commission reject the Company's proposed changes to the LFCR mechanism that include:

- Allowing the Company to receive recovery for generation costs;
- Increasing the recovery for distribution demand costs from 50 percent to 100 percent;
- Increasing the cap on recovered costs allowed for each year from 1 percent to 2 percent;
- Expanding the LFCR mechanism to include revenues lost from an Alternate Generation or "Buy-Through" provision to be established in the Company's tariff; and
- Combining the Energy Efficiency ("EE") and DG portions of the mechanism on the customer's bill.

Based on a review of the Company's application, supporting testimony, and responses to data requests, Staff recommends that the Commission accept the Company's proposed change to the LFCR mechanism to eliminate the Fixed Cost Option.

LONG-TERM RATE DESIGN PLAN

Q. Are significant changes occurring in the Company's capability to measure how and when customers are using energy?

A. Yes. Based upon discussions between Staff and the Company, the Company expects to complete a significant majority (subject to a few geographic limitations) of its installation of AMI by the end of 2016.[1]

Q. How has electric metering changed over time?

A. Initially there was no metering, and infant utilities charged either a flat rate per customer or charged by the number of light bulbs installed by a customer. This pricing methodology is still used for lighting (and other fixed load) customers because the number and wattage of bulbs can be accurately verified and enumerated. By not using meters, the costs of meters and meter reading do not need to be charged to those customers.

With the advent of energy meters at a reasonable cost, coupled with a wider range of lighting and appliances, utilities began to charge customers based upon the energy consumed. This type of rate design did not recognize different costs based upon demand (often expressed as load factor). Two customers using identical amounts of energy but with different usage patterns could have different levels of demand and require different amounts of generation, transmission and distribution equipment (at very different costs), and therefore one customer may be undercharged and the other overcharged if demand was not measured and taken into account. Alternatively, two customers who require the same equipment might use very different amounts of energy and again would result in one customer being undercharged and the other overcharged.

[1] TEP Response to STF 1.16

The introduction of demand meters, which measure peak demand usage within the billing period along with energy consumed, allowed for the introduction of rate forms such as the three-part rate (customer, demand and energy) or a variant (hours of use). The use of the demand meter and associated rates reduced the disparate impact of energy-only rates. Demand meters have generally not been used for residential customers due to the cost of the more complex meter, and the increased complexity of billing and the information that should be provided to the customer. The residential class was often seen as homogenous enough not to have wide usage disparities and therefore the cost of demand meters and their associated rate complexity was not justified.

For a number of years utilities have been able to measure the consumption of energy over very narrow time periods (hourly or even 15 minute intervals) but the challenge has been recording that data cost effectively and then providing that data to customers so that the customer could decide whether and how to respond and change their usage (energy) or usage pattern (demand). Interval data have been used for load research to provide an understanding of how different customers use energy and the data were typically recorded on magnetic tape and analyzed in bulk. While interval data were suitable for load research purposes, it was difficult to provide the data to a large number of customers at a reasonable cost.

Similarly, time-of-use meters could accumulate energy usage in a few time-differentiated periods but these data were only recorded and reported as On-Peak, Shoulder and Off-Peak and did not offer much information to the customer, such as when the energy was used on an interval basis.

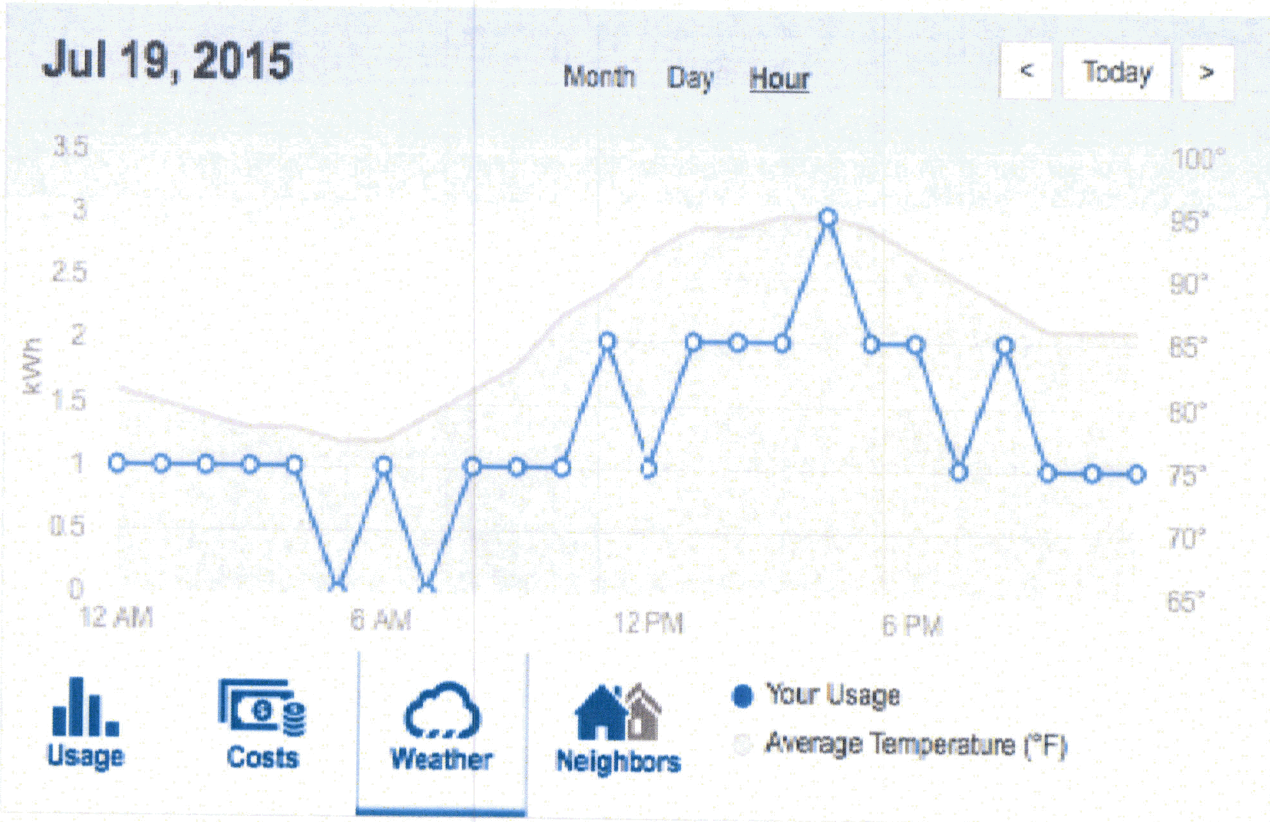
AMI has benefited from the declining costs of electronic versus mechanical metering devices and the ability to analyze data on a customer-specific basis. Utilities that have installed AMI often develop meter data management systems that allow for the extraction of energy and demand data for billing purposes. Unfortunately, some AMI planning does not go far enough and some utilities cannot provide individual customers their usage information in a form that supports customers' decisions about how and when to use energy more effectively and efficiently.

Q. Can you provide an example of conveying energy information to customers?

A. As a residential customer, my electric utility provides me with access to a portal where I can view my energy consumption.

On a macro basis, I can view my monthly consumption and compare it to an aggregate grouping of my neighbors and to a more limited aggregate grouping of my most efficient neighbors. The aggregate nature of these data protects my neighbors' privacy, and the portal limits my neighbors' access to my data, protecting my privacy. Various entities have opined that providing this "new" data encourages some customers into becoming more efficient in their use of energy.

My utility also provides me (with a two-day delay) my hourly energy consumption, which is equivalent to hourly demand. From this timely information, I can determine the peak period(s) of energy usage and then decide if I wish to change my energy timing, intensity and/or usage in the future.



Q. How did the confluence of new metering and information capabilities, changing customer characteristics lead Staff to consider a long-term rate design concept?

A. At this point in time, many utilities have the capability to record interval data as a result of the installation of AMI. Some utilities can provide that data to individual customers in a form that is somewhat easily understood, although some customer education is necessary. Residential customers are increasingly becoming non-homogenous as they adopt various forms of heat and distributed generation and as their lifestyles, demographics, and work patterns become increasingly more diverse.

Staff has raised the concept of offering a "plan" of how rate design should evolve so that the parties to this case could provide their input and the Commission could consider a plan in order to provide the Company's customers advance notice that changes are underway.

Q. Please articulate Staff's long-term rate design "plan".

A. There are a number of principles within this plan.

Rates should be based on costs derived from class cost of service studies not only at the class level but also to illuminate the unit costs of individual customer, demand and energy rates. Marginal costs should be given some consideration but embedded costs are the focus. There should be a place for test programs to determine if rate design can alter the need for capital investment and/or energy costs. When changes occur, gradualism should be used to temper the short-term impact until the next rate case.

Rate design should recognize the concepts of customer, demand and energy, and also recognize TOU and seasonality ("Three Part–TOU"). The number of rates available to customers should be minimized to avoid confusion as Three Part–TOU rates allow for cost-based billing of non-homogenous customers within one rate schedule. Inverted rates would be supplanted by the seasonal TOU component and the demand component which recognizes load factor.

Generation pricing would reflect the marketplace by considering seasonality, TOU, hourly pricing and demand response.

Rates should be supported by customer-specific usage information collected under extreme privacy and security, but available to customers along with tools to help them see the impact and make decisions. In the long-term, customers might receive cost "warning" using a simple red/yellow/green indication in their home or business and, for example, their demand controllers could access detailed price information online.

Rate subsidies, as determined appropriate, should be clearly delineated, be based on and computed from standard rates. For example, a Lifeline customer would be billed as a standard residential customer including all trackers and adjustment clauses but also receive a specific discount. Should a Lifeline customer's situation change for the better, the only change would be the removal of the Lifeline discount, which would be easily recognized by that customer. Hence, Staff's plan migrates Lifeline eligible customers to standard residential rates.

The Commission's Investigation of the Value and Cost of Distributed Generation (Docket No. E-00000J-14-0023) will assist Staff and the parties to determine an adequate methodology and quantification of compensation to potentially replace net metering. Ultimately if DG results in savings across the utility system and differentially for specific geographic areas (feeder), these effects would in time be separately identified using adders.

Q. Does the long-term migration of all customers of a class on to a single Three Part-TOU rate limit a customer's choice to one alternative?

A. Customers have very limited options now. The two-part rate allows the customer to increase or decrease his/her energy consumption to change the total bill. A two-part rate with TOU allows the customer to increase or decrease his/her energy consumption and when that energy is consumed but does not reflect the intensity or magnitude of use. The Three Part-TOU rate allows for a third dimension that the customer can use to affect the intensity of use.

One customer may come home from work, turn on the air conditioner, shower using hot water from an electric water heater and start the clothes washer all at the same time. A second customer may decide to linger with friends and have dinner out but have the air conditioner begin to cool the home before arrival, shower later in the evening and set the clothes washer to start at 4 AM. The intensity of multiple electric appliances operating together places a greater load on the system than the load of a single appliance. The Three Part-TOU rate prices the consumption and usage pattern differently by charging for both the demand (intensity) and energy consumed separately. In each case, the customers can choose the usage and pattern they wish and be charged appropriately for raising or lowering the utility's costs.

Q. What would be the long-term impact of this rate design "plan"?

A. Customers would have greater information available to make their own energy decisions, and rates would more accurately price those decisions and lessen the consequential impact on other customers. Over time, customer and demand charges would gradually increase and energy charges would become "purer" and lower for the distribution component. A customer could reduce costs by adjusting demand and/or by changing energy usage. The customer benefits from tools and education to take the best advantage of new rate forms.

Q. Do Three Part-TOU rates increase revenues for the utility?

A. No. If properly implemented the rates are neutral for the utility at the end of the Test Year. However, if customers choose to react to their present usage patterns the utility may see a decrease in revenue.

Q. Do Three Part-TOU rates increase costs for customers?

A. If a customer's usage pattern is the same as a "typical" customer then there should be no significant impact as Three Part-TOU rates are implemented. If a customer has an atypical usage pattern then costs may increase (for lower load factor customers) or decrease (for higher load factor) customers.

Q. Are these concepts new or new to the utility?

A. For medium and large customers, demand rates have been the norm and a Three Part-TOU rate is available. Flat rates are still appropriate for fixed, predictable loads such as lighting, cable amplifiers and traffic signals.

In the previous TEP rate case (Docket No. E-01933A-12-0504), I raised a number of these concepts but did not articulate them as a plan. Similarly, in this case the Company has raised some of these concepts but has not provided the data and education components critical for customer understanding of the Company's proposed residential and small general service demand rates.

Q. What are the important principles for the move towards the long-term rate design plan?

A. Rate design should not be changed until customers have private, secure, easy, timely and comprehensible access to their usage data.

Q. Are you recommending a mandatory transition to Three Part-TOU rates for Residential ("RES") and Small General Service ("SGS") customers?

A. No, Staff is not recommending a mandatory transition to Three Part-TOU rates in this case. In the on-going UNS Electric ("UNSE") case (Docket No. E-04204A-15-0142) the consideration of Three Part-TOU rates for RES and SGS customers was conflated with the outstanding issues of net metering and cost shifts related to solar DG customers. Before the impact of the rates at the level of revenue requirements generally accepted by the parties could be considered, customer concerns (both real and alleged) caused UNSE to withdraw the request for mandatory transition to Three Part-TOU rates for Residential and SGS customers. Staff then decided to withdraw its support because forcing a utility into a mandatory rate design change without the utility's support could lead to a flawed and failed transition.

Therefore, Staff is recommending in this case that an optional Three Part-TOU rate be made available to both RES and SGS customers. This optional rate may be attractive to customers that use energy efficiently and effectively.

Staff recommends that all RES and SGS customer bills include the customer's monthly On-Peak and Off-Peak demands (although the demand values would not be used for billing unless the customer has chosen the optional demand rate). Making the demand data available on the bill will allow customers to understand the concept of demand without any financial concerns.

Staff recommends that the Company should develop a customer information portal that would provide all customers with the ability to review their demand and energy consumption and evaluate various optional rate forms so that customers can make informed decisions about rates, energy efficiency and emerging technologies.

If the information now being measured and accumulated from AMI is not provided to customers then the full benefits of AMI will not be realized.

CLASS COST OF SERVICE STUDY

Q. What is the purpose of a fully allocated cost of service study?

A. Just as the rate case revenue requirements process studies each element of the Company's operations to determine the overall cost to operate the Company efficiently and effectively, a fully allocated cost of service study attempts to determine the individual cost to serve each customer class and subclass. A fully allocated class cost of service study is intended to assist the Commission to allocate revenue requirements among customer classes.

Q. How can a regulator use the class cost of service study?

A. Because customer classes use the utility's system on an interrelated or shared basis, regulators have historically used a fully allocated class cost of service study as a guideline to allocate revenue among classes. Regulators typically also consider economic, social, historical and other factors that may affect customers when determining revenue allocation. Such considerations often result in rates that deviate from strict cost of service.

Q. Are there limitations to a cost of service study?

A. Yes. A class cost of service study involves judgment and decisions on the part of the practitioner in assigning costs to the various customer classes. In some situations, decisions are made to use a particular allocation factor for a particular account. In other situations, data used to develop an allocation factor are not always complete and/or timely and the practitioner must deal with the resulting uncertainty. Consequently, the cost of service study acts as a guide in revenue allocation and in formulating rate design.

Q. Has the Company provided a class cost of service study?

A. Yes. The Company provided its CCoSS based on the Test Year (twelve-month period ended June 30, 2015).[2] Schedule G provides the individual class returns for the Company's five major service classes (Residential, General Service, Large General Service, Large Power Service and Lighting) along with the proposed 138 kV class.

[2] TEP Filing Schedule G

Q. Have you reviewed the CCoSS presented by the Company?

A. Yes. The CCoSS was provided as Schedules G-1 through 7. I performed a review of the allocations, developed data requests and reviewed the answers to Staff and other parties.

Q. Did the Company adjust or normalize its revenues?

A. Yes. The Company used a Test Year (twelve months ending June 30, 2015) and then adjusted it to reflect more normal or appropriate (from the Company's viewpoint) conditions.[3]

Q. Has the CCoSS changed from the prior rate case (Docket No. E-01933A-12-0291)?

A. Yes. The prior CCoSS had six service classes (Residential, Small General Service, Large General Service, Large Light & Power, Mining and Lighting). The Residential, Small General Service and Lighting classes are similar. The Company has created new rate schedules for Medium General Service ("MGS") and 138 kV based on demand and voltage criteria from the SGS and Large General Service ("LGS")[4] and Large Power Service ("LPS") rate schedules respectively[5].

Q. Are the changes to the service classes appropriate?

A. Yes. The differentiation by demand and voltage proposed by the Company is appropriate. The combination[6] within this case's CCoSS General Service class of Small General Service and Medium General Service classes should be disaggregated in the Company's next CCoSS as the transition to the MGS rate schedule will have been completed.

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[3] TEP Filing Schedule G-1 Inputs lines 1 to 4; Schedule G-2 lines 38 and 41
[4] Jones Direct 37:19
[5] Jones Direct 38:17
[6] TEP Response to Staff 20.13

Q. Have the Company's capacity resources changed since the last case?

A. Yes. The Company recently purchased a 75 percent share of the Gila River Power Plant Unit No. 3 combined cycle generating plant in concert with its affiliate UNSE.[7] The Company has changed its fuel mix by decreasing its coal capacity.[8]

Q. Please describe the attributes of a typical combined cycle generating unit?

A. A combined cycle generating unit is flexible in that it can start and stop operations (dispatch) easier than a coal or nuclear plant and is generally more thermally efficient than most other forms of fossil and nuclear generation. Typically, combined cycle plants are fueled by natural gas with distillate oil backup.

Q. What allocators does the Company use for its power supply expenses within the 2014 CCoSS?

A. For Other Production Plant, the Company uses the Demand Production ("DPROD") allocator, which is classified exclusively as demand.[9] For Other Production Expenses, the Company uses the Energy Production Power Supply – Design ("EFUELRD") allocator, which is classified exclusively as energy.[10]

Q. What allocator methodology did the Company use for DPROD?

A. The Company states that it used an Average and Excess allocator for production plant and expenses.[11]

[7] Hutchens Direct 7:26
[8] Hutchens Direct 7:21
[9] TEP Schedule G-3, Accounts 310-316
[10] TEP Schedule G-4, Account 501
[11] Jones Direct 26:3

Q. Has the Company changed the selection of the DPROD allocator since the last case?

A. Yes. Previously, the Company used a Peaks and Average allocator in its 2012 CCoSS.[12]

Q. Is the Company's Average & Excess & 4CP allocator a standard production methodology?

A. Although the Company stated that it is using an Average and Excess allocator it was non-specific in written testimony about the construction of the allocator. However, the Company provided a table within its testimony showing the impact of various allocators on class returns.[13] Within this table, the Company describes its Average and Excess allocator as Average & Excess & 4CP, which, based on the title, would be non-standard. Using coincident peaks (one or more) within the average and excess allocator is not a standard or recommended methodology.

Q. Why do you say that Average & Excess & 4CP does not appear to be a standard methodology?

A. The Electric Utility Cost Allocation Manual indicates:

> "If your objective is – as it should be using this method – to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands."[14]

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[12] Jones Direct 25:27
[13] Jones Direct 26:6
[14] NARUC Electric Utility Cost Allocation Manual January, 1992, page 50

Q. Did you explore this concern with the Company in the UNSE case?

A. Yes. The Company indicated that the DPROD allocator is a traditional A&E-NCP allocator but is allocating the 4CP value, thus the use of 4CP as an identifier. The Company confirmed this in an email during the UNS case.[15]

Q. Did the Company's DPROD allocator appear to meet the Company's description of an Average and Excess allocator?

A. No. The Company's DPROD allocator may be calculated using 4 CP along with the forms used for average and excess but the result is a 4CP allocator. This can be seen on Tab AvgEx&4CP of the Company's CCOSS which calculates the allocator.[16] The values for AED/4CP and 4CP Allocator are identical. The Company has indicated that the AED methodology was ordered in an Arizona Public Service case[17] (presumably Decision No. 69663). However, the methodology as implemented by the Company in this case is functionally the same as 4CP.

The effects of the equivalent 4 CP allocator can also be seen by Schedule G-1 line 7 where the Lighting class has not been allocated any fuel inventory. Even though the Lighting class has no responsibility under the 4CP portion of average and excess there should be an average component and none is apparent.

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[15] Email from Craig Jones dated 10/13/15 3:12 AM Item 1
[16] 2015 TEP Schedule G – COSS Competitively Sensitive Confidential.xlsx
[17] Jones Direct 26:4

Q. Did Staff explore the Company's calculation of the Average and Excess-NCP allocator?

A. Staff issued additional data requests to explore this issue. The Company subsequently issued a Revised Schedule G (UDR 1.001) that incorporated the expected AED-NCP allocator along with changes to meter allocations and customer allocations.[18]

Q. What is Staff's recommendation for an appropriate methodology for the DPROD allocator?

A. The appropriate methodology is Average and Excess-NCP (noncoincident peaks) as supported by the National Association of Regulatory Utility Commissioners ("NARUC") Manual as noted above. This allocator reflects both average load (energy) and excess load (demand) without algebraically becoming a CP allocator. This methodology is a better fit to a capacity plan that focuses on both energy and capacity (and selects an efficient and flexible generation technology such as Gila River Unit No. 3).

Q. Are there disproportional impacts between the present CCoSS and the prior one?

A. As Confidential Exhibit HS-2 shows, the change for the Residential and SGS classes is higher than the change for the Company in total. For example, Net Production Plant increased by 47 percent for the Company but 57 percent for the Residential class, 59 percent for the SGS class and 79 percent for the LPS class. Net Distribution Plant increased by 20 percent for the Company but 63 percent for the Residential class, 12 percent for the SGS class and 4 percent for the LPS class.

[18] TEP Response to STF 20.11

Q. What is the impact of the Company's change to the DPROD allocator?

A. The use of the new DPROD allocation methodology (A&E-NCP) raises the allocation to lower load factor classes (more costs) compared to the prior Peaks and Average methodology.

Q. What is the result of the Company's capacity allocation proposal in this case?

A. The Company CCoSS provides a means to compare the impact of demand allocators (Average & Excess-NCP and Peaks & Average & 4CP) after the Company's proposed increase.[19] Assuming that only the production plant allocation methodology has changed, the class return for the Residential class has gone from 2.50 percent using P&A to 0.92 percent using A&E-NCP; General Service class 20.02 percent using P&A to 19.06 percent using A&E-NCP; Large General Service 20.04 percent using P&A to 25.81 percent using A&E-NCP.

Q. Does the Company's allocation of income taxes by class have an impact on the returns calculated?

A. Yes. The Company appears to allocate class income taxes on the sum of return times rate base plus operating expenses (without income taxes). Using this methodology, positive taxes are allocated to a class that is not providing enough revenue to cover expenses. An alternative methodology (sometimes used) calculates class income taxes based on the profitability of the class, more akin to how a business is taxed. The Company's methodology magnifies the disparity between positive and negative class returns. However, when all classes have positive returns close to the Company's return the effect is smaller and of less consequence than the other changes discussed above.

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[19] TEP Revised Schedule G Tab AvgEx&4CP

There is no impact from the use of the Company's ratebase tax allocation methodology compared to allocating based on net income before income taxes when all classes reach parity (Unitized Rate of Return ("UROR") = 1.000). However, the impact under present conditions is significant. Assuming Staff's proposed revenue increase and revenue allocation (37.5% of UROR = 1.000) the Residential class UROR would increase from 0.028 to 0.308 due to the reallocation of $ 20.73 million of income tax expense. This approximates to a revenue impact for the Residential class of $33.63 million.

Q. What CCoSS recommendation does Staff have for the Commission?

A. There are two major effects operating in the same direction in this case. While the Company's net distribution plant has increased by 20 percent, net production plant has increased by 47 percent. Simultaneously, the Company has changed its production plant allocation methodology from Peak & Average to Average & Excess–NCP. These two changes magnify the individual impact on classes. Therefore, the Commission should use the Company's CCoSS as a general guideline and invoke gradualism in its class revenue allocation decision for this case.

REVENUE ALLOCATION

Q. What non-cost considerations should the Commission consider during its deliberations on revenue allocation?

A. The Commission should consider the relative positions (from the CCoSS) of the classes along with the qualitative issues such as economic conditions for consumers, the business climate for commercial and industrial customers and past practices when deciding what portion of a revenue increase is allocated to each class.

Q. What principles do you generally use to allocate revenue among rate classes?

A. I have used the following principles:

- The individual rate classes should be gradually moved toward an UROR of 1.000 over one or more rate cases depending on the frequency of rate cases and the distance of the class' UROR from 1.000.
- There should be an upper bound of 150 percent for any class' percentage increase in revenue compared to the overall percentage increase in revenue.
- There should be a lower bound of 50 percent for any class' increase compared to the overall increase.

Q. Are there other concepts that apply in this case?

A. The purchase of the combined cycle generating unit was intended to stabilize energy costs, which provides benefits to all customers. Therefore, it would be inappropriate to reduce rates for any customer class because that would send a confusing message about the new plant expenditure.

Q. What is the Company's proposed revenue allocation?

A. Based on Schedule H-1, the Company is proposing to allocate its requested $109.5 million increase 59.7 percent to the Residential class, 7.3 percent to the General Service class, 34.7 percent to the Large General Service class, -2.9 percent to the Large Power Service and 138kV classes and 1.1 percent to the Lighting class.

Q. Have you modeled various revenue allocations based on Staff's recommended revenue requirements?

A. Confidential Exhibit HS-4 models Staff's proposed $ 49,400,000 increase a number of ways. For comparison purposes the increase was allocated:

- Equal percentage increase (across the board by revenue)
- Moving all of the classes to the same return (UROR equals 1.000)
- Moving the Residential and Lighting classes 50 percent of the amount needed to reach parity (and decrease all other classes by $9.87 million)
- Moving the Residential and Lighting classes 45 percent of the amount needed to reach parity (and decrease all other classes by $3.94 million)
- Moving the Residential and Lighting classes 40 percent of the amount needed to reach parity (and increase all other classes by $1.98 million)
- Moving the Residential and Lighting classes 35 percent of the amount needed to reach parity (and increase all other classes by $7.91 million)
- Moving the Residential and Lighting classes 33.33 percent of the amount needed to reach parity (and increase all other classes by $9.89 million)
- Moving the Residential and Lighting classes 30 percent of the amount needed to reach parity (and increase all other classes by $13.84 million)
- Moving the Residential and Lighting classes 37.5 percent of the amount needed to reach parity (and increase all other classes by $4.95 million)

The remaining revenues from the other classes (GS, LGS, LPS and 138kV) were allocated based on their respective expected revenues (Test Year Adjusted Margin Revenues[20] plus Test Year Proposed Fuel Revenues[21]).

Q. What is Staff's recommendation on revenue allocation?

A. Based upon the present CCoSS, the principles discussed above, the impact of the purchase of the combined cycle plant, the change in allocation methodology and the relative impacts between classes, Staff recommends that the eventual revenue requirements be allocated by increasing the Residential and Lighting classes 37.5 percent of the amount needed to reach parity and increasing all other classes by $4.95 million (10 percent of the overall increase proposed by Staff) to obtain the total revenue requirement.

As shown on page 1 (lines 30-43) of Confidential Exhibit HS-4, under Staff's recommended revenue allocation the Residential class receives 87.2 percent of Staff's proposed increase

[20] TEP Revised Schedule G-1 Inputs line 3
[21] TEP Revised Schedule G-2 line 40

compared to the Company's proposal of 59.7 percent, although Staff's increase is a lesser absolute dollar amount. Under Staff's proposal, all classes receive an increase while the Company's proposal decreased the revenue requirement for the Large Power Service/138kV classes.

This revenue allocation does not follow my general principles in that the Residential and Lighting classes have negative returns and holding to some of my principals would require four rate cases to reach parity.

Q. If Staff's recommended revenue allocation is adopted what will the class returns be?

A. The results of the proposed revenue allocation are forecasted in Confidential Exhibit HS-4. The UROR of the "low UROR" classes (Residential and Lighting) will increase and the UROR of the "high UROR" classes (except the LGS class) will decrease, moving classes towards parity. To decrease the UROR of the LGS class a rate decrease would be needed.

Q. Have some classes been subsidized by other classes in the past?

A. Yes. Confidential Exhibit HS-3 summarizes the Company's latest two CCoSS. In the 2011 CCoSS, the UROR [line 39] is less than 1.0 for the Large General Service class and negative for the Residential, Large Light & Power and Mining classes indicating subsidization by the Small General Service class. In the present CCoSS, the UROR [line 13] is negative for the Residential class. The Lighting class has been negative in both CCoSS.

Q. Please explain why, if the Residential and Lighting classes are being subsidized by other classes, Staff is not recommending class revenue increases to bring those classes to parity, which would be consistent with the rate design plan Staff is recommending and you have detailed above.

A. Staff's plan articulates the concept that "Rates should be based on costs derived from class cost of service studies…"; however, the plan is a long-term plan.

Confidential Exhibit HS-4 shows that to bring the Residential class to parity would require a class revenue increase of 232 percent of the total increase recommended by Staff and an increase of 7 percent of the total increase recommended by Staff for the Lighting class (significantly higher than the Company's proposal). Confidential Exhibit HS-2 demonstrates that significant changes have occurred between the two CCoSS due to the impacts of the acquisition of a portion of Gila River Unit No. 3 and the changes in various allocators.

As explained above, revenue allocation is not just an algorithm-based process but it is tempered by a Commission's evaluation of other factors. Also, Staff's recommendation to move the Residential class towards removing the subsidy allows for the completion of the process in following cases.

Q. Does Staff's revenue allocation reflect the late breaking (June 6, 2016) confidential information about a significant customer?

A. No. On June 6th the Company provided information on the expected partial closure of a significant customer. This information included "initial projection of the changes to" annual billing determinants (demand and energy) by rate schedule but did not include the breakdown by season or time of use. "The Company expects to make an adjustment in its Rebuttal filing to reduce billing determinants to reflect the known and measureable reduction in sales to this customer."

Because the billing determinants were only initial projections and not complete, Staff has not made an estimate of the impact on each class of this still unfolding event. Staff has discussed with the Company a list of information that it expects to need to evaluate this emerging situation. At this time, Staff has not determined its position on the event or the revenue or rate implications.

RATE DESIGN

Q. Please summarize the Company's rate design proposal.

A. The Company's rate design objectives are "To align rate structures with our customers' evolving energy use", "To reduce the level of cross-subsidies between customers" and "To give the Company an appropriate opportunity to recover its fixed costs."[22]

The Company has focused on the use of a three-part rate design (customer, demand and energy charges) that would be mandatory for all new DG customers[23] and optional for other RES and SGS customers.[24] The Company suggests that these changes are to better align the Commission's policies with the Company's need for fixed cost recovery and system usage.[25] The Company is also supporting gradualism when making rate design changes.[26] For new DG customers, the Company is proposing monthly bill credits for any excess energy delivered to the Company's system.[27]

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[22] Hutchens Direct 11:23 – 12:16
[23] Hutchens Direct 18:22, Dukes Direct 8:18
[24] Dukes Direct 24:3
[25] Hutchens Direct 20:1
[26] Hutchens Direct 23:26
[27] Hutchens Direct 24:9

Q. What was the Company's primary concern in developing its rate design proposals?

A. As I understand the Company's approach, the focus is the recovery of fixed costs. A concern is expressed that seasonal customers, vacant homes or businesses, and DG customers (with their associated low kWh consumption) limit the Company's ability to recover fixed costs.[28]

Q. Is this focus on fixed costs sufficient to support rate design changes?

A. Yes. If fixed costs are not properly accounted for in the rate design, intra-class subsidies will occur. The challenge is how to and how fast to make the changes. RES and SGS customers have a simple rate design and even the acceptance of TOU rates in these classes has been limited.[29] With new rate forms, some customers need education and support to achieve a meaningful transition.

Q. Is the Company's unit cost analysis in Schedule G-6-1 Revised useful in evaluating its proposed Basic Service Charges?

A. The Company's information shows direct customer costs, an amount that includes meters, billing and collection, meter reading costs and the service line or drop. The Company has indicated that it used a minimum-sized system to allocate portions of the distribution system (such as poles, wires, transformers) to the customer component.[30] These costs are included in the customer-related unit costs.

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[28] Dukes Direct 11:10
[29] Schedule H-2 approximately 2.3% of residential customers
[30] TEP Response to STF 1.38 and STF 1.32

Q. What changes does the Company propose for the Residential Electric Service (Rate RES) rate?

A. **The Company** is requesting an increase in the Basic Service Charge from $10.00 to $20.00.[31] Energy charges also are proposed to increase,[32] and the Company is proposing to eliminate the third and fourth tiers because the tiers are being used for fixed cost recovery.[33]

Q. What changes does the Company propose for the Residential Time-of-Use (Rate RES-TOU) rate?

A. The Company is requesting an increase in the Basic Service Charge from $11.50 to $20.00 for TOU customers,[34] and the addition of a second tier to match the configuration of the RES rate.[35]

Q. What are the residential customer costs?

A. The Company's information shows that customer costs are $17.19.[36] This amount includes meters, billing and collection, meter reading costs and the service (line or drop) and the components that form the minimum-sized system.

Q. What changes does Staff recommend to the proposed RES residential rate?

A. Staff recommends the following modifications of the Company's proposal:

- The existing third and fourth tiers should be eliminated and the remaining inclination should be flattened as the residential customer's load factor increases as usage increases, which does not support inclined rates.[37]

[31] Jones Direct 43:9 and 43:27
[32] TEP Schedule H-3
[33] Jones Direct 45:1
[34] TEP Schedule H-3
[35] Jones Direct 45:15
[36] TEP Revised Schedule G-6-1 line 24

- All residential Basic Service Charges should be $17.00 to approximate the Company's costs. With the advent of AMI, residential customers will be using the same meter and therefore have the same costs.

- The revenue allocated to the Residential class should be collected first by an increase in the Basic Service Charge up to the level proposed here, with the remainder (if any) recovered by increased energy charges to begin to levelize the tiers. Applying the revenue increase to the Basic Service Charge first and eliminating the third and fourth tiers will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

Q. What is the impact on residential customers of Staff's recommendations?

A. Based upon Staff's recommended overall increase in revenue requirements along with its revenue allocation and rate design changes, the average residential RES customers would see an increase of $6.96 per month or an 8 percent increase as shown in Exhibit HS-5 page 1.

Q. What changes does the Company propose for the SGS rate?

A. For SGS customers, the Company is requesting an increase in the Basic Service Charge from $16.50 and $17.50 (TOU) to $30.00.[38] The energy charges also are proposed to increase.[39] This non-demand class will be limited to customers with a maximum energy consumption of 24,000 kWh accumulated across two consecutive months.[40] The unit cost information in Schedule G-6-1 indicates that customer costs for the SGS Class are $38.43.[41]

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[37] Dukes Direct 25:1
[38] Jones Direct 46:23
[39] TEP Schedule H-3, Page 12
[40] Jones Direct 47:1
[41] TEP Revised Schedule G-6-1 line 24

Q. What changes does Staff recommend to the SGS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The Basic Service Charge should be $26.80, this amount was determined to meet the reduced revenue requirements for the General Service class.

- The revenue allocated to the SGS class should be collected first by an increase in the Basic Service Charge up to the level proposed by the Company, with the remainder (if any) recovered by increased energy charges. Applying the revenue increase to the Basic Service Charge first will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

- The Company's proposal to move a customer to the new MGS rate "if the customer's consumption meets or exceeds 24,000 kWh in consecutive months" is appropriate as it does not penalize a customer for a single usage excursion.

Q. What is the impact on small general service customers of Staff's recommendations?

A. Based upon Staff's recommended overall increase in revenue requirements along with its revenue allocation and rate design changes, general service SGS customers would see increases as shown in Exhibit HS-5 page 2.

Q. The existing RES and SGS rates are not Three-Part-TOU rates and therefore are not in accordance with the Staff's long-term rate design plan. What do you recommend for an initial step?

A. Staff recommends that the Commission approve in this proceeding optional Three-Part-TOU rates for RES and SGS customers. As customers gain experience with these optional rates and see their demand on their monthly bills, the Commission can consider other steps in the Company's next rate case.

Q. The Company is proposing the Residential Electric Service Demand (RES-D), Residential Electric Service Time-of-Use Demand (RES TOU-D), Small General Service Demand (SGS-D) and Small General Service Time-of-Use Demand (SGS TOU-D) rates. Do these rates meet Staff's rate design concepts?

A. The Company has not defined the source of the various values and tiers within the proposed demand rates. Also, the demand charge will apply to all time periods. The Company has not explained the theory and background of these rates, and the Company should provide more support in its rebuttal testimony. At present without this information, Staff does not support these rates for any purpose.

Q. What is the Company's proposal for a new MGS rate?

A. The Company wants to establish a new MGS rate for existing Small and Large General Service ("LGS") customers with demand between 20 kW and 250 kW.[42] This rate class will have the same demand measurement and ratchet as the existing LGS class.[43] The Company is requesting a Basic Service Charge of $40.00. Demand charges are proposed to be $7.00 per kW summer and $5.00 per kW winter.[44] The Company is proposing that any customer that exceeds the 250 kW cap "for a billing month will be automatically moved, in the subsequent month to the new LGS rate class. The customer must remain there for at least 12 months without exceeding the 250 kW demand to qualify to move back to MGS."[45]

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[42] Jones Direct 37:19 and 43:25
[43] Jones Direct 38:1 and 49:3
[44] TEP Schedule H-3, Page 15
[45] Jones Direct 47:10

Q. Is the Company's proposal to create a new MGS class and MGS rate schedule appropriate?

A. Conceptually, yes. Creating rate classes based on demand (and voltage) is appropriate. However, the Company has indicated that the transition of almost 4,000 SGS customers from the existing non-demand rate to the MGS rate which will include demand charges and a demand ratchet may have adverse impacts for a number of those customers. The Company's filing provides no information about these customers and the impact of the new MGS rate on them. Staff has requested further details about the support and education to be provided to these customers.[46] The Company has indicated that once the particulars of the new rate (along with more recent usage) have been determined the Company will contact customers that appear to have increases above normal. Potential MGS customers were not provided specific notice of the specific proposed change. Staff conceptually supports the establishment of the MGS class subject to further details about the Company's plans for notice and the education and support program. The Company should address in its rebuttal this significant change for the MGS customers.

Q. Is the Company's proposed customer charge for MGS customers appropriate?

A. The unit cost information in Revised Schedule G-6-1 indicates that customer costs for the SGS and LGS Classes respectively \$38.43 and \$536.17.[47] Unfortunately, the unit costs were not differentiated for the MGS rate class.

Q. What changes does Staff recommend to the MGS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The three-part rate design is appropriate as it reflects Staff's long-term rate design.

[46] TEP Response to STF 20.08
[47] TEP Revised Schedule G-6-1 line 24

- The $40.00 Basic Service Charge requested by the Company may be too low in light of the mixed CCoSS. However, as a transition this situation is acceptable.

- The ratchet provision proposed for the new MGS rate should be delayed because the Company has not provided detailed information on the impact of the creation of this new rate schedule on the almost 4,000 customers who at present are not subject to a demand charge and demand ratchet.

- The Company's proposal that "any customer exceeding the cap for a billing month will automatically be moved, in the subsequent month, to the new LGS rate class", is abrupt and too short a period to determine if the move is appropriate, nor has the impact been determined. Absent further information, Staff does not support this "one-chance" provision and suggests the Company address this issue in its rebuttal testimony.

- The Company should develop and implement a Medium General Service cost of service class in its next rate case to verify the costs to be used in the future MGS rate design.

Q. Is there some risk when significant rate design changes are made?

A. Yes. Rate design changes may have unintended results for "outlier" or "non-normal" MGS customers that do not fit neatly into their apparent customer class. The imposition of a demand ratchet (if approved) may also have unforeseen impacts. These risks are increased when customer notice and outreach is limited or has not been performed.

Staff recommends, as provided for in the previous TEP settlement (Docket No. E-01933A-12-0291), the Commission should keep the rate design portion of this rate case open for at least 18 months after the completion of the transition to MGS rates to account for unanticipated customer rate impacts that are determined to be inconsistent with the public interest.

Q. What changes does the Company propose for the LGS rate?

A. For LGS rate customers, the Company is requesting an increase in the customer charge from $775.00 and $950.00 (TOU) to $1,000.00. Demand charges are proposed to increase from $15.25 to $17.50 per kW.[48] This class will retain the existing a minimum demand of 200 kW, and there will be a demand eligibility cap of 5,000 kW above which the customer will be moved to the LPS-TOU class.[49]

Q. Is the Company's increase in the customer charge for LGS customers appropriate?

A. The unit cost information in Revised Schedule G-6-1 indicates that customer costs for the Large General Service Class are $536.17.[50]

Q. What changes does Staff recommend to the LGS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The three-part rate design is appropriate as it retains the existing rate structure.

- The Basic Service Charge should remain at its present level, as the charge requested by the Company is not supported by the unit costs.

- The revenue allocated to the LGS rate should be collected first by an increase in the demand charge, with the remainder (if any) recovered by increased energy charges.

[48] TEP Schedule H-3, Page 19
[49] Jones Direct 47:14
[50] TEP Schedule G-6-1 line 24

Applying the revenue increase to the demand charge first and then to energy charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

- The proposal to impose a maximum demand of 5,000 kW has not been supported in the Company's filing. Absent support indicating the number of customers affected and the extent of the impact, Staff does not support this provision and suggests the Company address this issue in its rebuttal testimony.

Q. What rate changes does the Company propose for the LPS customer class?

A. For LPS rate customers, the Company is requesting no change in the $2,000 Basic Service Charge. The summer On-Peak Demand charge is proposed to decrease from $20.49 to $18.00 per kW.[51] This demand class will continue to have a minimum demand of 3,000 kW.[52] It is important to note that there will only be a TOU rate for LPS customers.[53]

Q. Is the Company's no change in the Basic Service Charge for Large Power Service customers appropriate?

A. The unit cost information in Revised Schedule G-6-1 indicates that customer costs for the Large Power Service Class are $17,490.91.[54] The difference between the proposed Basic Service Charge and the customer costs is substantial and should be explained by the Company in its rebuttal.

Q. What changes does Staff recommend to the LPS rate?

A. Staff recommends the following modifications of the Company's proposal:

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[51] TEP Schedule H-3, Page 18
[52] Jones Direct 48:2
[53] Jones Direct 47:19
[54] TEP Response to STF 2.057, Line 23

- The three-part rate design is appropriate as it retains the existing rate structure.
- The Basic Service Charge should move toward a cost based rate subject to the Company's rebuttal information.
- The revenue allocated to the LPS rate should be collected first by an increase in the Basic Service Charge, with the remainder (if any) recovered by increased demand and then energy charges. Applying the revenue increase to the Basic Service Charge first and then to demand charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

Q. Is the Company's proposal for a new 138 kV rate appropriate?

A. The Company is proposing a new 138kV TOU rate for customers able and willing to take service at transmission level voltages. The Company is proposing a Basic Service Charge of $3,000, demand charges of $17.15 and $12.49 per kW (summer and winter respectively) and a minimum demand of 10,000 kW. These rates are similar to the LPS rates.[55] Schedule H-1 shows no customers on this rate, while Revised Schedule G-2 indicates one customer on the rate. While the Company has provided specific details on the development of portions of this rate[56], it has not provided enough information to render an opinion on the Basic Service Charge and other elements. Staff suggests the Company address this issue in its rebuttal testimony.

Q. What changes is the Company proposing for the Lighting Service rate?

A. The Company is proposing a 46 percent increase in certain lighting charges[57] in order to raise the performance of this underperforming class.[58] The wattage charge does not define

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[55] Jones Direct 53:20
[56] Jones Direct 54:17
[57] TEP Schedule H-3
[58] Jones Direct 49:17

whether it is solely the lamp wattage or if a ballast load is included.[59] Staff suggests the Company address this issue in its rebuttal testimony.

Q. Does Staff agree with the rate changes that the Company has proposed for the Lighting Service rate?

A. Revised Schedule G-1 indicates the Lighting class has a return of -13.61 percent compared to a total system return of 5.52 percent.[60] After the Company's proposed increase the class will still have a negative return.[61] Due to the existing very negative return of the Lighting class it may take several cases to move the Lighting class towards parity with the other rate classes. Consistent with Staff's revenue allocation for the Residential class, Staff is proposing an increase of $1.377 million[62] for the Lighting class as compared to the Company's proposed $1.246 million increase[63].

Interruptible Rates

Q. Please describe the Company's interruptible rate proposals?

A. Based on the Company's testimony[64] and the tariff sheet provided, the Company is not proposing any significant changes in existing interruptible Rider-12.

Lifeline

Q. Please describe the Company's proposal for Lifeline customers?

A. In its last rate case, the Company began a transition to the inclusion of Lifeline customers on existing residential rates but with a fixed Lifeline discount. Under this concept, Lifeline customers can easily determine their discount and the impact on their bills if their financial

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[59] Exhibit CAJ-4 Schedule LTG
[60] TEP Revised Schedule G-1, line 36
[61] TEP Revised Schedule G-2, line 35
[62] Staff Confidential Exhibit HS-4, page 1, line 36
[63] Staff Confidential Exhibit HS-4, page 4, line 6
[64] Jones Direct 57:3

situation were to improve. The existing $9.00 Lifeline discount for these Lifeline customers is simple to understand and administer.[65] However, there are still legacy Lifeline customers (some dating from the mid 1990s with substantial discounts) and there are multiple configurations of the Lifeline discount (27).[66] The Company is proposing to increase the discount to $15.00 and further consolidate the 27 rates to five available to new and existing customers and 5 that would apply to existing customers.[67] For existing frozen Lifeline rate customers, the Company is proposing to use a flat monthly $15 discount[68] from the standard residential rates and in some cases also reduce the Basic Service Charge in order to approximate the existing subsidies and limit the increase to an amount similar to non-Lifeline customers.[69]

Q. What is the value/cost of the Lifeline discounts?

A. The Company estimates the discounts totaled $1,798,110 during the Test Year for nearly 15,000 Lifeline customers.[70]

Q. Does Staff support the Lifeline proposal?

A. In keeping with Staff's long-term plan for rate design, the Staff supports the Company's Lifeline proposal subject to a few concerns.

- The impact on Lifeline customers of any rate change is dependent on the level of residential rate change and the structure of the residential rates. Staff recommends that the validation of the Lifeline impact and the required discounts be performed after the revenue allocation and residential rate design is finalized.

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[65] Jones Direct 58:10
[66] Jones Direct 58:15
[67] Jones Direct 57:20
[68] Jones Direct 57:26
[69] Jones Direct 59:3
[70] Jones Direct 58:4

- The Company should "prove out" that the level of Lifeline discounts after the finalized changes in rates is at or above the Test Year value.

- The roster of Lifeline customers should be examined, and any existing Lifeline customer who would be better off (on an annual basis) on the flat monthly discount should be moved to the new Lifeline discount rate.

Distributed Generation

Q. Is the Company proposing that all DG customers move to a three part rate?

A. Yes. The Company argues that DG customers are partial requirements customers and the existing two-part rate design is inappropriate for this service.[71]

Q. Should residential DG customers be moved to the Residential Electric Service Demand (Res-D) or Residential Time-of-Use Demand (RES TOU-D) rate at the close of this case as requested by the Company?

A. No. Consistent with Staff's long-term rate design plan, the actions taken behind the meter of any customer are not the sole determinant of which rate the customer must use. Staff is awaiting the Commission's decisions in the UNS case (15-0142) and the Value and Cost of Distributed Generation case (14-0023) and may update its position on the appropriate rate for DG customers in rebuttal or later at hearing.

Q. What is the Company's proposal for excess energy produced by distributed generation and fed back into the Company's system?

A. The Company has proposed a new net metering rider that allows customers with DG to sell monthly excess energy production to the Company at the Renewable Credit Rate.[72] This

[71] Dukes Direct 5:8

[72] Dukes Direct 4:26 and Tilghman Direct 10:13

proposal would apply to all customers who submitted a completed application after June 1, 2015,[73] while existing DG customers (and applications submitted before June 1, 2015) would stay on the current rider for up to 20 years from the date of approval.[74]

Q. Does the Company's proposal eliminate the banking option for new DG customers?

A. Yes. The Company proposes to pay for energy received with a monthly bill credit.[75]

Q. How is the Renewable Credit Rate ("RCR") defined?

A. The Company proposes a RCR of 5.84 cents per kWh, which it argues is equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system. The project in question is due for completion in 2015.[76]

The Company indicates that it would file an annual RCR update similar to the existing Market Cost of Comparable Conventional Generation when it makes its annual REST filing based on the most recent comparable utility scale purchased power agreement for renewable energy.[77]

Q. Is a utility scale photovoltaic facility a reasonable proxy for the value of energy provided by photovoltaic DG?

A. The Company argues that a utility scale photovoltaic facility is a reasonable proxy for photovoltaic DG because it has similar production characteristics (seasonality, time of day and response to weather). If the procurement of the utility scale energy is from one or more independent suppliers, then the resulting price is a reasonable estimate of the market value at

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73 Dukes Direct 4:21 and Tilghman Direct 10:20
74 Dukes Direct 4:23
75 Dukes Direct 4:27
76 Tilghman Direct 9:14
77 Tilghman Direct 10:6

that approximate location at that point in time and for the period of the Purchase Power Agreement ("PPA").

Excess energy from a photovoltaic DG installation is not entirely representative of a utility scale PV facility because the DG customer is providing the net output equal to the photovoltaic output less any energy consumed by the customer and therefore may have a delivery profile different from a utility scale facility.

Q. Did the Company perform a system loss study?

A. Yes. The Company provided a summary of its detailed loss study[78] (classified as competitively sensitive) that is based on identifying different stages in the transmission and distribution system including transformer losses.

Q. Should the purchase price for excess DG energy be adjusted for losses?

A. Yes. Most of the energy the Company generates or purchases should be assumed to transit the Company's transmission system, and for most customers the Company's distribution system. A portion of the energy consumed by a distribution customer is lost from the point of generation to the ultimate customer. Since it is likely that energy is provided by a DG customer to nearby neighbors, losses should be added to the RCR. Based on the Company's loss study summary losses could be substantial (value not included due to confidentiality).

Q. What other potential savings and costs are due to the existence of DG?

A. There may be savings in transmission charges; however, the Company has not addressed this issue. Other parties to this case may be able to add to the record in this area.

[78] CONFIDENTIAL TEP Response to STF 1.35

Some participants may consider savings from deferred or avoided distribution investment. In the on-going UNS case, the Company has identified a TEP substation[79] as a possible preferred location for the installation of solar generation along with supporting technologies. If DG can be shown to defer or eliminate required distribution investment, DG customers that provide the needed "support" should receive a locational adder.

Q. Does Staff have a recommendation as to how to determine the value of excess energy?

A. It is early in this rate case proceeding and many interested parties have not yet filed their positions on the value of excess energy. Commission Docket No. E-00000J-14-0023, which is intended to examine the value and cost of DG, will continue to provide useful information to the parties in this rate case. Therefore, for the time being, Staff does not propose any changes to the existing net metering tariff or waivers of the net metering rules but it may update its position in its Surrebuttal testimony or later at the hearing in this case.

Staff does oppose the Company's reliance on a single Purchased Power Agreement to establish the RCR and also opposes at this time any change in net metering absent the adoption of three-part rates, subject to decisions in the Commission's value and cost of DG docket.

Staff notes that in the various cases at this time that the Company and solar industry interveners propose that existing DG solar customers as of a specified date be "grandfathered". During those proceedings, Staff has offered a number of proposals intended to mitigate the impact on existing solar customers. Staff is not necessarily opposed to some form of grandfathering as a mitigation factor, but is concerned that any form of grandfathering must clearly define the elements of the current rate design that are included in

[79] UNS Response to STF 2.034

grandfathering (such as basic service and energy charges which change after each rate case), establish a fair and reasonable date for delineating which DG customers are grandfathered, define how long a facility is grandfathered based on lifespan or other factors such as return on investment, and not impede the Commission's ability to address rates for these customers in the future. The decision should also close the window on future grandfathering of newer vintage facilities and allow future Commissions the ability to revisit grandfathering at each subsequent rate case.

Service Fee Changes

Q. Please describe the changes proposed by the Company to the TEP Electric Statement of Charges?

A. The table below details the changes the Company is proposing. The Company is requesting a new charge for Consumption History Request and Interval History Request on an hourly basis:[80]

[80] Exhibit CAJ-3 Original Sheet 801 and Jones Direct 70:9

Description	Existing Rate	TEP's Proposed Rate
Service Transfer Fee	$20.00	$26.00
Customer-Related Meter Re-read	$20.00	$26.00
Special Meter Reading Fee (including Customer Self-Reads)	$20.00	$26.00
Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours – Single-Phase Service	$32.00	$38.00
Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Single-Phase Service	$57.00	$61.00
Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours – Three-Phase Service	$78.00	$129.00
Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Three-Phase Service	$216.00	$271.00
Service Reestablishment under other than usual operating procedures (including Automated Meter Opt-Out Set-Up Fee) – Single Phase Service	$150.00	$187.00
Single-Phase Line Extension Charge per Foot	$17.00	$17.00
Three-Phase Line Extension Charge per Foot	$27.00	$27.00
Underground Differential Line Extension Charge per Foot	$21.00	$21.00
PME Switchgear Cabinet	$20,500.00	$20,500.00
Meter Test	$186.00	$211.00
Returned Payment Fee	$10.00	$10.00
Late Payment Finance Charge	1.5%	1.5%
Residential Solar – Company Owned Program Processing Fee	$250.00	$250.00
Consumption History Request and Interval History Request	----	$65.00 an hour

Q. What did you find during your review of the cost support data for these charges?

A. The Company provided a worksheet detailing the underlying costs for each of these charges.[81] The information provided supports the Company's request except as detailed below.

[81] UDR 1.001 2015 TEP Service Fees.xlsx

Q. What did you find during your review of the cost support data for the Service Establishment after Regular Business Hours Three Phase charge?

A. The Service Establishment – Regular Business Hours Three Phase entails 1 hour of a Metering Journeymen compared to performing the work after hours using 2 hours of a TEP Lineman. The Company should explain why a Lineman is used for the after hours work when a TEP Metering Journeyman can perform the task After Hours – Single Phase for 1.5 hours. The data would indicate that a TEP Metering Journeyman is available after hours and may have different work rules.

Q. What other concerns do you have with the Consumption History Request and Interval History Request charge?

A. There appears to be some confusion as to when this charge will be applied. The Company states this charge will apply only after the first time a customer requests interval data, but this is not clear on the Statement of Charges.[82] Also, this charge should not apply if the Company develops a means to allow customers to look up or request their usage information online or through a mobile application that does not require the work of an employee. Finally, Staff recommends that this charge not apply to MGS customers for a period of six months after the mandatory transition of MGS customers.

Q. Is the inclusion of Automated Meter Opt-Out Set-Up within the classification of Service Reestablishment under other than usual operating conditions appropriate?

A. No. The proposed charge of $187 for the Automated Meter Opt-Out Set-Up Fee has been set assuming "other than usual operating procedures". Changing the meter for an Opt-Out customer, which entails setting a digital meter that does not transmit data wirelessly, does not have to be done as a special event and can be scheduled during normal working hours.

[82] Jones Direct 74:20

Therefore, the charge should be the proposed $38 for Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours to reflect this situation.

Buy-Through

Q. Please describe the Experimental Rider 14 "Buy-Through" proposal submitted by the Company?

A. The Company was required to introduce the "Buy-Through" as a result of a settlement during the merger process,[83] but the Company does not support this tariff change.[84]

Q. What is the Staff position on the "Buy-Through"?

A. Because the Company is not supporting this concept, there is no record describing the benefits to non-participating customers. Staff does not object to a "Buy-Through" mechanism if there are no adverse impacts and no costs to all other customers. Staff is concerned that Buy-Through customers may return when the market becomes tight (expensive) and thus impact customers that did not or could take advantage of the Buy-Through provisions. Staff opposes recouping any allegedly lost Buy-Through revenue and likewise opposes any deferral of allegedly lost Buy-Through revenue. This opposition to recouping lost incremental revenues extends to the use of the LFCR for that purpose.[85]

Staff looks forward to reviewing testimony in support of the "Buy-Through" by other parties.

[83] Jones Direct 61:18
[84] Jones Direct 61:23
[85] Jones Direct 80:4

AMI Opt-Out

Q. What is the AMI Opt-Out?

A. Some customers have raised concerns about the use of meters that transmit data wirelessly back to the Company. These customers wish to retain their existing mechanical meters, which would then require the Company to read the meter by travelling to the Opt-Out customer's premise, which raises the costs of serving these customers compared to all other customers.

Q. Is the retention of mechanical meters for Opt-Out customers appropriate?

A. No. All customers can benefit from the information provided by AMI meters that record interval data. Mechanical meters cannot provide the data required for, and the potential benefits of, new rate forms and the information that a customer can use to manage their energy usage and intensity.

Q. Is there an alternative that deals with the concerns and provides the interval data for new rate forms?

A. This issue was raised informally with the Company and it suggested a solid-state meter with recording capabilities, which accumulates but does not transmit information.[86] The Company would read the interval data by visiting the customer's premise monthly.

Q. What is Staff's recommendation?

A. If a customer decides to Opt-Out, the Company should install a non-transmitting recording device and read that meter monthly. Because the number of Opt-Out customers is expected to be small and geographically dispersed, the costs of the monthly meter reading should be the Special Meter Reading Fee that requires a premise visit. The costs of the new meter

[86] Email from Brenda Pries dated 11/23/15 at 11:30 AM

installation should be recouped from the customer requesting this non-standard meter (at the proposed $38 for Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours) along with the monthly reading costs (at the proposed $26 Special Meter Reading Fee). Staff will monitor the number of special read customers to determine if the Special Meter Reading Fee remains appropriate as the number of customers using the Opt-Out develops.

Economic Development

Q. Please describe the economic development program proposed by the Company?

A. The Company is proposing an Economic Development Rider 13 ("EDR") for current or potential commercial or industrial customers that meet certain economic development criteria within the Company's service area. The EDR will be available to customers with a projected peak demand of 1,000 kW or more and a load factor of 75 percent or higher. Discounts would decline over a five-year period. New load would be limited to 50 MW.[87]

Q. What reasons did the Company provide as support for the EDR program?

A. The Company argues that its service territory has been slow to recover from the economic downturn post 2007.[88]

Q. What are the specific qualifications to obtain the EDR?

A. The EDR qualifications are linked to existing Arizona state tax credit programs, which appear to be designed to create new in-state above median wage jobs with healthcare benefits.[89]

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[87] Dukes Direct 31:9
[88] Dukes Direct 30:3
[89] Dukes Direct 31:20

Q. What levels of discount are offered?

A. For economic development (requires the building of new facilities), the discount starts at 20 percent and declines to 2.5 percent. For economic redevelopment (occupying vacant facilities), the discount starts at 30 percent and declines to 5 percent.[90]

Q. How will the discounts be recouped?

A. The Company's proposal did not address this issue. Staff explored this question in a data request. The Company responded that most of the revenues will reduce incremental revenues between rate cases, and will not be included in a cost of service analysis. The Company expects to include these additional customers and/or loads in any future rate proceedings by applying the applicable retail rate when establishing test year adjusted revenues. Therefore, no subsidy or discount will be allocated to any other customer or rate class.[91]

Q. Will existing customers be protected from the impact of new capital expenditures?

A. The Company's proposal did not address this issue. Staff explored this question in a data request. The Company responded that the present rules and regulations approved by the Commission governing line extensions and new services would apply equally to these new customers or incremental loads.[92]

Q. At present the Commission is encouraging energy efficiency so isn't the EDR program the direct opposite because it will increase energy sales?

A. Conceptually, electric energy efficiency programs have not focused on limiting the increase in new customers but focused on increasing the efficiency of energy usage. Economic

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[90] Dukes Direct 32:6
[91] TEP Response to STF 1.17
[92] TEP Response to STF 1.18

development rates can increase the number of employers, employees and maybe machinery and are expected to provide economic benefits within the utility's service territory. The Company's EDR program is geared towards the reuse of vacant facilities, which have some existing unused (or underused) electrical distribution capacity. Although EDR customers are proposed to be on a standard rate schedule with a discount, if the Commission is concerned about load growth, requirements could be added, such as using only time-of-use rates and/or interruptible service.

Q. What is Staff's recommendation for the EDR?

A. The proposed EDR has limits and is biased towards existing facilities. The Company should address the potential impact of new energy requirements for the incremental load in its rebuttal. Assuming that the energy costs are not significant, then Staff supports this limited (volume and time) program to increase employment in the service territory. Staff's support does not extend to any request for recoupment of the lost incremental revenues absent a supporting record in some future proceeding.

LOST FIXED COST RECOVERY

Q. What purpose does the LFCR mechanism serve?

A. The LFCR mechanism, as approved by the Commission, serves to compensate the Company between rate cases for the revenue lost by the Company's compliance with established requirements for EE and DG.

Q. What is your experience with the LFCR mechanism in Arizona?

A. On behalf of Staff, I sponsored the LFCR mechanism in the Arizona Public Service ("APS") rate case (Docket No. E-01345A-11-0224), the TEP rate case (Docket No. E-01933A-12-0291) and the last UNSE rate case (Docket No. E-04204-12-0504).

Q. What has been the impact of the LFCR mechanism on the Company's customers?

A. "The combined EE and DG surcharge from the first TEP LFCR filing was approximately 0.7 percent and the 2015 LFCR filing resulted in approximately a 0.4 percent incremental increase for a total adjustment of approximately 1.1 percent."[93]

Q. Please describe the Company's LFCR proposal in this proceeding.

A. The Company's LFCR proposal is to change the established LFCR mechanism to increase the revenue recovered due to the effects of energy efficiency and distributed generation.[94]

Q. What is the revenue impact of the Company's proposed changes to the LFCR mechanism?

A. The Company estimates the impact of the recovery of generation costs and 100 percent of the demand costs to be approximately $13,000,000.[95] "However, based on the data supporting the 2015 LFCR filing, the Company estimates that the incremental LFCR increase for including generation costs would have incrementally increased the total LFCR adjustment by an additional 1.7 percent to a total adjustment of 2.8 percent."[96]

Q. What changes is the Company proposing that will affect the presentation on the customer's bill?

A. Presently, the utility is required to show the EE and DG components of the LFCR mechanism on the bill as two separate items. The Company is proposing to combine the two items into a single line item.[97]

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[93] Jones Direct 80:23
[94] Jones Direct 77:22
[95] Jones Direct 78:19
[96] Jones Direct 80:27
[97] Jones Direct 80:10

The Company is also asking for permission to no longer offer the Fixed Cost Option in the LFCR mechanism.[98]

Q. What portions of the Company's proposal to modify the LFCR mechanism do you recommend that the Commission accept?

A. I support the Company's proposal to remove the Fixed Cost Option from the LFCR because no customer has used that option at the Company[99] or at the Company's affiliate UNS[100].

Q. What portions of the Company's proposal to modify the LFCR mechanism do you recommend that the Commission not accept?

A. The Commission should not accept the proposals that will increase the revenue impact on customers including:

- Allowing the Company to receive recovery for generation costs
- Increasing the recovery for distribution demand costs from 50 percent to 100 percent
- Increasing the cap on recovered costs allowed for each year from 1 percent to 2 percent
- Using the LFCR to recoup lost revenues resulting from any Alternate Generation Services ("Buy Through")

Further, the Commission should not accept the change proposed by the Company to combine the EE and DG portions of the mechanism on the customer's bill as that provision was originally implemented by the Commission[101] and serves to highlight for the customer the relative impacts of EE and DG, which affect different customer subclasses.

[98] Jones Direct 79:18
[99] Jones Direct 79:19
[100] UNS Filing 15-0142 Jones Direct 77:15
[101] July 11, 2013, Open Meeting

Q. Why should the Commission reject including generation and purchased power in the LFCR mechanism?

A. Purchased power is fungible and is not affected if energy is delivered to a new customer, an existing customer using slightly more energy, an economic development customer or sold off-system. Therefore, the Company has many opportunities to adjust its energy supply. Further, the impact of this change would more than double the effect of the LFCR.

Q. What is the Company's forecast for sales?

A. The Company's Firm Load Obligations (System Coincident Peak Demand (MW)) shows increasing requirements in Net Retail Demand (which is net of DG and EE).[102] The load forecast shows a trend of increasing total numbers of customers[103] and the reference case (without the effects of EE and DG) shows increasing sales to retail customers.[104] The Company's Firm Wholesale Requirements are also forecasted to increase starting in 2017.[105]

The Company has released its 2016 Preliminary Integrated Resource Plan. The Preliminary 2016 IRP is forecasting continued increases in the number of customers.[106] The weather normalized Retail Energy Forecast indicated "While use per customer is expected to remain weak over the near term, the largest impact on near-term sales is the anticipated curtailment of copper mining operations recently announced by TEP's largest retail customer." And "After 2020, sales growth is dominated by residential and commercial sales but at a pace below historical average."[107] "… [peak] demand is expected to drop in 2016. This is largely attributed to the mining class. Afterward, TEP's retail peak demand is expected to grow over

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[102] TEP 2014 Integrated Resource Plan Table 4 (page 28)
[103] TEP 2014 Integrated Resource Plan Chart 10 (page 49)
[104] TEP 2012 Integrated Resource Plan Chart 12 (page 52)
[105] TEP 2014 Integrated Resource Plan Table 6 (page 56)
[106] TEP 2016 Preliminary Integrated Resource Plan Chart 3 (page 26)
[107] TEP 2016 Preliminary Integrated Resource Plan Chart 5 (page 28)

time."[108] After a decrease from 2017 to 2018, firm wholesale requirements are expected to rise through 2021.[109] Table 3, which includes the reductions in load due to the impact of distributed generation and energy efficiency, indicates increasing Total Retail Customers, Residential Sales Growth, Commercial Sales Growth, Retail Demand.[110]

Q. Could the proposed EDR and the Company's LFCR changes create a situation where some generation could be double collected?

A. Yes. The Company is proposing an economic development rate in this case that if successful would increase energy sales, peak demand and revenue. In an unusual twist, if the Company's proposal to include generation in the LFCR mechanism is approved, the Company could bill existing customers for the generation costs within the LFCR mechanism, redirect the generation (energy and capacity) to a new customer attracted by the proposed economic development rates and effectively double collect on that load.

Q. Why should the Commission reject increasing from 50 percent to 100 percent the distribution demand component in the LFCR mechanism?

A. Distribution costs are not as fungible and some distribution assets cannot serve other customers within the short term. Therefore, a reduction in per customer sales may result in a shortfall in revenues to cover distribution fixed costs. The LFCR adopted by the Commission provides a mechanism to recapture the portion of distribution costs that are collected on a volumetric (per kWh) basis. Some of the Company's rate schedules collect distribution costs using demand charges, which will remain constant or change slower than a straight volumetric rate.

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[108] TEP 2016 Preliminary Integrated Resource Plan Chart 7 (page 29)
[109] TEP 2016 Preliminary Integrated Resource Plan Table 2 (page 30)
[110] TEP 2016 Preliminary Integrated Resource Plan Table 3 (page 31)

Q. Why should the Commission reject increasing from 1 percent to 2 percent the cap in the LFCR mechanism?

A. If the Commission does not accept the Company's proposed changes to the LFCR, then the increase in the cap is not necessary.

Q. Why should the Commission reject using the LFCR mechanism to recoup lost revenues resulting from Alternate Generation Service ("Buy Through")?

A. Alternate Generation Service is not available to all customers and it appears that the benefits would flow through to those customers able to use "Buy Through". It would be inappropriate to charge all customers for benefits that accrue primarily to a select few customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Testimony - Howard Solganick

Arizona Corporation Commission
Case – UNS Electric Docket No. E-00000J-14-00023 (February 2016)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered the value and cost of distributed generation and other related issues.

Case – UNS Electric Docket No. E-04204A-15-0142 (November 2015 and December 2015)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered cost of service, revenue allocation, rate design, revenue decoupling and other related issues.

Case – UNS Electric Docket No. E-04204A-12-0504 (June 2013 and July 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Tucson Electric Power Company Docket No. E-01933A-12-0291 (December 2012 and January 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Arizona Public Service Company Docket No. E-01345A-11-0224 (November and December 2011)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica Public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days

LINE	CCoSS Comparisons	A	B	C	D	CONFIDENTIAL	G
	2015 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	[redacted]	LIGHTING
	2011 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE		LIGHTING
1	**Total Intangible Plant**						
2	2015 CCoS	$160,246,771	$92,285,178	$33,712,632	$16,278,713		$1,437,572
3	% of Total 2015	1.000	0.576	0.210	0.102		0.009
4	2011 CCoS	$95,706,208	$46,410,743	$19,856,966	$11,432,151		$4,926,836
5	% of TOTAL	1.000	0.485	0.207	0.119		0.051
6	% Change 2015 vs. 2011	67.4%	98.8%	69.8%	42.4%		-70.8%
7	Ratio 1						
8	Ratio 2						
9							
10	**Accumulated Depreciation - Intangible Plant**						
11	2015 CCoS	$119,977,698	$69,094,454	$25,240,846	$12,187,968		$1,076,319
12	% of Total 2015	1.000	0.576	0.210	0.102		0.009
13	2011 CCoS	$61,094,680	$29,626,599	$12,675,823	$7,297,788		$3,145,077
14	% of TOTAL	1.000	0.485	0.207	0.119		0.051
15	% Change 2015 vs. 2011	96.4%	133.2%	99.1%	67.0%		-65.8%
16	Ratio 1						
17	Ratio 2						
18							
19	**Net Intangible Plant**						
20	2015 CCoS	$40,269,073	$23,190,724	$8,471,787	$4,090,745		$361,253
21	% of Total 2015	1.000	0.576	0.210	0.102		0.009
22	2011 CCoS	$61,094,680	$29,626,599	$12,675,823	$7,297,788		$3,145,077
23	% of TOTAL	1.000	0.485	0.207	0.119		0.051
24	% Change 2015 vs. 2011	-34.1%	-21.7%	-33.2%	-43.9%		-88.5%
25	Ratio 1						
26	Ratio 2						
27							
28							
29							
30	**Total Production Plant**						
31	2015 CCoS	$2,080,992,837	$1,073,843,310	$466,579,966	$256,045,939		$1,826,258
32	% of Total 2015	1.000	0.516	0.224	0.123		0.001
33	2011 CCoS	$1,638,020,642	$793,047,554	$340,438,186	$209,658,321		$13,205,137
34	% of TOTAL 2011	1.000	0.484	0.208	0.128		0.008
35	% Change 2015 vs. 2011	27.0%	35.4%	37.1%	22.1%		-86.2%
36	Ratio 1						
37	Ratio 2						
38							
39	**Accumulated Depreciation - Production Plant**						
40	2015 CCoS	$796,297,495	$410,909,025	$178,538,076	$97,976,666		$698,823
41	% of Total 2015	1.000	0.516	0.224	0.123		0.001
42	2011 CCoS	$764,915,641	$370,333,842	$158,976,320	$97,905,316		$6,166,476
43	% of TOTAL	1.000	0.484	0.208	0.128		0.008
44	% Change 2015 vs. 2011	4.1%	11.0%	12.3%	0.1%		-88.7%
45	Ratio 1						
46	Ratio 2						
47							
48	**Net Production Plant**						
49	2015 CCoS	$1,284,695,342	$662,934,285	$288,041,889	$158,069,273		$1,127,436
50	% of Total 2015	1.000	0.516	0.224	0.123		0.001
51	2011 CCoS	$873,105,001	$422,713,712	$181,461,866	$111,753,005		$7,038,660
52	% of TOTAL	1.000	0.484	0.208	0.128		0.008
53	% Change 2015 vs. 2011	47.1%	56.8%	58.7%	41.4%		-84.0%
54	Ratio 1						
55	Ratio 2						
56							
57							
58							
59	**Distribution**						
60	**Total Distribution Plant**						
61	2015 CCoS	$1,441,783,351	$954,902,876	$274,539,855	$101,816,262		$29,776,532
62	% of Total 2015	1.000	0.662	0.190	0.071		0.021
63	2011 CCoS	$1,243,492,787	$604,282,700	$257,413,460	$134,539,804		$135,131,561
64	% of TOTAL	1.000	0.486	0.207	0.108		0.109
65	% Change 2015 vs. 2011	15.9%	58.0%	6.7%	-24.3%		-78.0%
66	Ratio 1						
67	Ratio 2						
68							
69	**Accumulated Depreciation- Distribution**						
70	2015 CCoS	$579,194,987	$382,375,665	$108,264,696	$42,054,468		$13,376,247
71	% of Total 2015	1.000	0.660	0.187	0.073		0.023
72	2011 CCoS	$524,017,237	$252,347,477	$109,006,084	$57,438,334		$57,969,714
73	% of TOTAL	1.000	0.482	0.208	0.110		0.111
74	% Change 2015 vs. 2011	10.5%	51.5%	-0.7%	-26.8%		-76.9%
75	Ratio 1						
76	Ratio 2						
77							
78	**Net Distribution Plant**						
79	2015 CCoS	$862,588,364	$572,527,211	$166,275,158	$59,761,794		$16,400,285
80	% of Total 2015	1.000	0.664	0.193	0.069		0.019
81	2011 CCoS	$719,475,551	$351,935,222	$148,407,376	$77,101,470		$77,161,847
82	% of TOTAL	1.000	0.489	0.206	0.107		0.107
83	% Change 2015 vs. 2011	19.9%	62.7%	12.0%	-22.5%		-78.7%
84	Ratio 1						
85	Ratio 2						
86							

LINE	CCoSS Comparisons	A	B	C	D	CONFIDENTIAL	G
	2015 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	[redacted]	LIGHTING
	2011 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE		LIGHTING
87	**Total General Plant**						
88	2015 CCoS	$314,077,737	$180,875,530	$66,075,511	$31,905,674		$2,817,588
89	% of Total 2015	1.000	0.576	0.210	0.102		0.009
90	2011 CCoS	$222,233,554	$107,767,559	$46,108,651	$26,545,902		$11,440,305
91	% of TOTAL	1.000	0.485	0.207	0.119		0.051
92	% Change 2015 vs. 2011	41.3%	67.8%	43.3%	20.2%		-75.4%
93	Ratio 1						
94	Ratio 2						
95							
96	**Accumulated Depreciation - General Plant**						
97	2015 CCoS	$86,548,234	$49,842,621	$18,207,972	$8,792,027		$776,423
98	% of Total 2015	1.000	0.576	0.210	0.102		0.009
99	2011 CCoS	$61,611,122	$29,877,037	$12,782,974	$7,359,477		$3,171,663
100	% of TOTAL	1.000	0.485	0.207	0.119		0.051
101	% Change 2015 vs. 2011	40.5%	66.8%	42.4%	19.5%		-75.5%
102	Ratio 1						
103	Ratio 2						
104							
105	**Net General Plant**						
106	2015 CCoS	$227,529,503	$131,032,909	$47,867,538	$23,113,648		$2,041,165
107	% of Total 2015	1.000	0.576	0.210	0.102		0.009
108	2011 CCoS	$160,622,433	$77,890,522	$33,325,677	$19,186,425		$8,268,641
109	% of TOTAL	1.000	0.485	0.207	0.119		0.051
110	% Change 2015 vs. 2011	41.7%	68.2%	43.6%	20.5%		-75.3%
111	Ratio 1						
112	Ratio 2						
113							
114							
115							
116	**Total Electric Plant In Service**						
117	2015 CCoS	$3,997,100,696	$2,301,906,895	$840,907,964	$406,046,589		$35,857,951
118	% of Total 2015	1.000	0.576	0.210	0.102		0.009
119	2011 CCoS	$3,199,453,192	$1,551,508,556	$663,817,262	$382,176,178		$164,703,838
120	% of TOTAL	1.000	0.485	0.207	0.119		0.051
121	% Change 2015 vs. 2011	24.9%	48.4%	26.7%	6.2%		-78.2%
122	Ratio 1						
123	Ratio 2						
124							
125							
126	**Total Accumulated Depreciation**						
127	2015 CCoS	$1,582,018,414	$912,221,765	$330,251,591	$161,011,129		$15,927,812
128	% of Total 2015	1.000	0.577	0.209	0.102		0.010
129	2011 CCoS	$1,411,638,679	$682,184,956	$293,441,200	$170,000,916		$70,452,931
130	% of TOTAL	1.000	0.483	0.208	0.120		0.050
131	% Change 2015 vs. 2011	12.1%	33.7%	12.5%	-5.3%		-77.4%
132	Ratio 1						
133	Ratio 2						
134							
135							
136	**Total Net Plant In Service**						
137	2015 CCoS	$2,415,082,282	$1,389,685,129	$510,656,373	$245,035,460		$19,930,139
138	% of Total 2015	1.000	0.575	0.211	0.101		0.008
139	2011 CCoS	$1,787,814,513	$869,323,600	$370,376,062	$212,175,262		$94,250,907
140	% of TOTAL	1.000	0.486	0.207	0.119		0.053
141	% Change 2015 vs. 2011	35.1%	59.9%	37.9%	15.5%		-78.9%
142	Ratio 1						
143	Ratio 2						
144							

LINE	CCoSS Comparisons	A	B	C	D	CONFIDENTIAL	G
	2015 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	[redacted]	LIGHTING
	2011 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE		LIGHTING
145	**Expenses**						
146	**Total Production Expense**						
147	2015 CCoS	$421,678,184	$189,441,644	$91,112,246	$65,231,386		$1,459,547
148	% of Total 2015	1.000	0.449	0.216	0.155		0.003
149	2011 CCoS	$475,802,168	209,998,747	107,228,213	63,736,243		2,665,042
150	% of TOTAL	1.000	0.441	0.225	0.134		0.006
151	% Change 2015 vs. 2011	-11.4%	-9.8%	-15.0%	2.3%		-45.2%
152	Ratio 1						
153	Ratio 2						
154							
155	**Transmission**						
156	2015 CCoS	$95,464,952	$49,262,255	$21,404,223	$11,746,034		$83,779
157	% of Total 2015	1.000	0.516	0.224	0.123		0.001
158	2011 CCoS	$90,028,056	$43,587,075	$18,710,990	$11,523,134		$725,774
159	% of TOTAL	1.000	0.484	0.208	0.128		0.008
160	% Change 2015 vs. 2011	6.0%	13.0%	14.4%	1.9%		-88.5%
161	Ratio 1						
162	Ratio 2						
163							
164	**Total Distribution Expenses**						
165	2015 CCoS	$24,085,317	$16,319,423	$4,409,813	$1,553,987		$568,559
166	% of Total 2015	1.000	0.678	0.183	0.065		0.024
167	2011 CCoS	$22,965,413	$10,697,159	$5,009,944	$2,507,307		$2,656,260
168	% of TOTAL	1.000	0.466	0.218	0.109		0.116
169	% Change 2015 vs. 2011	4.9%	52.6%	-12.0%	-38.0%		-78.6%
170	Ratio 1						
171	Ratio 2						
172							
173	**Total Customer Account Expense**						
174	2015 CCoS	$21,874,552	$18,486,473	$2,354,053	$256,909		$725,774
175	% of Total 2015	1.000	0.845	0.108	0.012		0.033
176	2011 CCoS	$19,452,377	$16,352,738	$2,201,896	$289,630		$314,063
177	% of TOTAL	1.000	0.841	0.113	0.015		0.016
178	% Change 2015 vs. 2011	12.5%	13.0%	6.9%	-11.3%		131.1%
179	Ratio 1						
180	Ratio 2						
181							
182	**Administration and General Expense**						
183	2015 CCoS	$75,722,484	$66,049,810	$6,582,497	$126,620		$2,960,302
184	% of Total 2015	1.000	0.872	0.087	0.002		0.039
185	2011 CCoS	$65,884,580	$32,766,584	$13,479,222	$8,081,864		$881,638
186	% of TOTAL	1.000	0.497	0.205	0.123		0.013
187	% Change 2015 vs. 2011	14.9%	101.6%	-51.2%	-98.4%		235.8%
188	Ratio 1						
189	Ratio 2						
190							
191	**Total Operations & Maintenance Expense**						
192	2015 CCoS	$638,825,490	$339,559,606	$125,862,831	$78,914,936		$5,797,960
193	% of Total 2015	1.000	0.532	0.197	0.124		0.009
194	2011 CCoS	$674,132,594	$313,402,303	$146,630,266	$86,138,178		$7,242,777
195	% of TOTAL	1.000	0.465	0.218	0.128		0.011
196	% Change 2015 vs. 2011	-5.2%	8.3%	-14.2%	-8.4%		-19.9%
197	Ratio 1						
198	Ratio 2						
199							
200							
201	**501 - FUEL PPFAC Eligible**						
202	2015 CCoS	$303,925,690	128,678,471	64,710,927	50,743,086		1,356,208
203	% of Total 2015	1.000	0.423	0.213	0.167		0.004
204	2011 CCoS	$292,189,698	121,102,785	69,067,097	40,234,780		1,184,824
205	% of TOTAL	1.000	0.414	0.236	0.138		0.004
206	% Change 2015 vs. 2011	4.0%	6.3%	-6.3%	26.1%		14.5%
207	Ratio 1						
208	Ratio 2						
209							

CCoSS Comparisons

		A	B	C	D	CONFIDENTIAL	G
	2015 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	[redacted]	LIGHTING
	2011 CCoS Classes	TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE		LIGHTING
210	**Sales (kWh) G-2**						
211	2015 CCoS	9,020,707,871	3,651,120,932	1,839,512,456	1,477,690,240		38,940,096
212	% of Total 2015	1.000	0.405	0.204	0.164		0.004
213	2011 CCoS	9,332,107,047	3,887,303,965	2,179,138,260	1,222,821,614		37,430,790
214	% of TOTAL	1.000	0.417	0.234	0.131		0.004
215	% Change 2015 vs. 2011	-3.3%	-6.1%	-15.6%	20.8%		4.0%
216	Ratio 1						
217	Ratio 2						
218							
219	**Service Charges (G-2)**						
220	2015 CCoS	5,301,752	4,624,515	460,877	8,865		207,267
221	% of Total 2015	1.000	0.872	0.087	0.002		0.039
222	2011 CCoS	5,112,747	4,423,307	446,993	7,446		234,797
223	% of TOTAL	1.000	0.865	0.087	0.001		0.046
224	% Change 2015 vs. 2011	3.7%	4.5%	3.1%	19.1%		-11.7%
225	Ratio 1						
226	Ratio 2						
227							
228	**Usage per Customer (month)**						
229	2015 CCoS		790	3,991	166,688		188
230	% of Total 2015						
231	2011 CCoS		879	4,875	164,225		159
232	% of TOTAL						
233	% Change 2015 vs. 2011		-10.2%	-18.1%	1.5%		17.9%
234	Ratio 1						
235	Ratio 2						

LINE	CCoSS Comparisons	A	B	C	D	CONFIDENTIAL	G
	2015 CCoS Classes REVISED (Exhibit G-1)	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	[redacted]	LIGHTING
1	**Total Ratebase**	$2,104,677,691	$1,205,895,803	$444,808,100	$214,240,229		$17,302,998
2	% of Total Ratebase		57.3%	21.1%	10.2%		0.8%
3							
4	**Total Operating Revenue**	$958,869,144	$431,971,346	$269,010,674	$114,103,130		$4,966,796
5	% of Total Sales		45.1%	28.1%	11.9%		0.5%
6							
7	**Total Operating Expenses**	$842,650,381	$455,187,352	$169,373,777	$100,248,300		$7,321,251
8	% of Operating Expenses		54.0%	20.1%	11.9%		0.9%
9							
10	**Operating Income**	$116,218,763	-$23,216,006	$99,636,897	$13,854,830		-$2,354,455
11							
12	**Rate of Return**	5.52%	-1.93%	22.40%	6.47%		-13.61%
13	UROR		-0.349	4.057	1.171		-2.464
14							
15	**kWh Sales**	9,020,707,874	3,651,120,932	2,132,332,869	1,177,162,108		38,940,096
16	% of Sales		40.5%	23.6%	13.0%		0.4%
17							
18	**Test Year Adjusted Customers**	441,808.67	385,376.25	38,564.58	577.58		17,272.25
19							
20	**Sales per Customer**		9,474	55,293	2,038,082		
21							
22							
23							
24						CONFIDENTIAL	
25	**2011 CCoS Classes (Exhibit G-1)**	TOTAL	RESIDENTIAL SERVICE	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE	[redacted]	LIGHTING
26							
27	**Total Ratebase**	$1,519,073,362	$738,869,476	$307,503,874	$182,758,071		$82,433,877
28	% of Total Ratebase		48.6%	20.2%	12.0%		5.4%
29							
30	**Total Operating Revenue**	$842,583,379	$379,166,672	$238,207,819	$103,539,944		$4,056,085
31	% of Total Sales		45.0%	28.3%	12.3%		0.5%
32							
33	**Total Operating Expenses**	$813,648,717	$382,116,983	$175,393,746	$102,595,530		$13,480,786
34	% of Operating Expenses		47.0%	21.6%	12.6%		1.7%
35							
36	**Operating Income**	$28,934,662	-$2,950,311	$62,814,073	$944,414		-$9,424,701
37							
38	**Rate of Return**	1.90%	-0.40%	20.43%	0.52%		-11.43%
39	UROR		-0.210	10.724	0.271		-6.002
40							
41	**kWh Sales**	9,332,107,047	3,887,303,965	2,179,138,260	1,222,821,614		37,430,790
42	% of Sales		41.7%	23.4%	13.1%		0.4%
43							
44	**Test Year Adjusted Customers**	426,062.25	368,608.92	37,249.42	620.50		19,566.42
45							
46	**Sales per Customer**		10,546	58,501	1,970,704		
47							
48							
49							
50	**2015 vs 2011**						
51	Increase in Class Ratebase	38.6%	63.2%	44.7%	17.2%		-79.0%
52							
53	Increase in Revenue	13.8%	13.9%	12.9%	10.2%		22.5%
54							
55	Increase in Operating Expenses	3.6%	19.1%	-3.4%	-2.3%		-45.7%
56							
57	Increase in kWh Sales	-3.3%	-6.1%	-2.1%	-3.7%		4.0%
58							
59	Increase in Test Year Adjusted Customers	3.7%	4.5%	3.5%	-6.9%		-11.7%
60							
61	Increase in Sales per Customer		-10.2%	-5.5%	3.4%		

		TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	<<<<<< CONFIDENTIAL >>>>>>	LIGHTING
		(A)	(B)	(C)	(E)	[redacted]	(H)
	TEP G-1 REVISED						
1	TOTAL OPERATING REVENUE	$958,869,144	$431,971,346	$269,010,674	$114,103,130		$4,966,796
2	TOTAL OPERATING EXPENSES	$842,650,381	$455,187,352	$169,373,777	$100,248,300		$7,321,251
3	OPERATING INCOME	$116,218,763	($23,216,006)	$99,636,897	$13,854,830		($2,354,455)
4							
5	TOTAL RATE BASE	$2,104,677,691	$1,205,895,803	$444,808,100	$214,240,229		$17,302,998
6							
7	RATE OF RETURN ON RATE BASE	5.52%	-1.93%	22.40%	6.47%		-13.61%
8	(ORIGINAL COST RATE BASE)	UROR	-0.349	4.057	1.171		-2.464
9							
10	TEST YEAR ADJUSTED SALES (kWh)	9,020,707,874	3,651,120,932	2,132,332,869	1,177,162,108		38,940,096
11	TEST YEAR ADJUSTED MARGIN REVENUES	605,398,982	275,887,975	184,448,887	68,460,569		3,298,783
12	TEST YEAR ADJUSTED FUEL REVENUES	321,741,284	135,724,786	78,695,943	43,017,444		1,459,034
13	TEST YEAR ADJUSTED SERVICE CHARGES	5,301,705	4,624,515	462,775	6,931		207,267
14							
15	**All UROR = 1.000**						
16	Rate of Return on Rate Base	6.12%	6.12%	6.12%	6.12%		6.12%
17	UROR	1.000	1.000	1.000	1.000		1.000
18							
19	Proposed Sales Revenue	$958,724,672	$519,431,996	$194,741,644	$112,679,505		$8,326,352
20							
21	Change in Margin Revenue	$49,400,000	$114,865,550	($54,418,170)	($6,524,150)		$3,671,360
22	% Change in Margin Revenue	8.2%	41.6%	-29.5%	-9.5%		111.3%
23	% of the Class Change in Margin Revenue	100.0%	232.5%	-110.2%	-13.2%		7.4%
24							
25							
26	Change in Total Revenue	$31,584,406	$107,819,235	($68,403,187)	$1,201,492		$3,568,534
27	% Change in Total Revenue	3.4%	26.2%	-26.0%	1.1%		75.0%
28	% Class Change in Total Revenue	100.0%	341.4%	-216.6%	3.8%		11.3%
29							
30	**37.5% to UROR = 1.000**						
31	Rate of Return on Rate Base	6.12%	0.17%	18.91%	9.72%		-7.14%
32	UROR	1.000	0.028	3.089	1.587		-1.166
33							
34	Proposed Sales Revenue	$958,724,672	$447,641,027	$251,625,319	$120,383,208		$6,031,752
35							
36	Change in Margin Revenue	$49,400,000	$43,074,581	$2,465,505	$1,179,553		$1,376,760
37	% Change in Margin Revenue	8.2%	15.6%	1.3%	1.7%		41.7%
38	% of the Class Change in Margin Revenue	100.0%	87.2%	5.0%	2.4%		2.8%
39							
40							
41	Change in Total Revenue	$31,584,406	$36,028,266	($11,519,512)	$8,905,195		$1,273,934
42	% Change in Total Revenue	3.4%	8.8%	-4.4%	8.0%		26.8%
43	% Class Change in Total Revenue	100.0%	114.1%	-36.5%	28.2%		4.0%

		TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	<<<<<< CONFIDENTIAL >>>>>>	LIGHTING
		(A)	(B)	(C)	(E)	[redacted]	(H)
	50% to UROR = 1.000						
1	Rate of Return on Rate Base	6.12%	1.36%	17.25%	8.07%		-4.49%
2	UROR	1.000	0.222	2.818	1.318		-0.733
3							
4	Proposed Sales Revenue	$958,724,672	$461,999,221	$244,243,184	$116,851,429		$6,490,672
5							
6	Change in Margin Revenue	$49,400,000	$57,432,775	($4,916,630)	($2,352,226)		$1,835,680
7	% Change in Margin Revenue	8.2%	20.8%	-2.7%	-3.4%		55.6%
8	% of the Class Change in Margin Revenue	100.0%	116.3%	-10.0%	-4.8%		3.7%
9							
10							
11	Change in Total Revenue	$31,584,406	$50,386,460	($18,901,646)	$5,373,416		$1,732,854
12	% Change in Total Revenue	3.4%	12.2%	-7.2%	4.8%		36.4%
13	% Class Change in Total Revenue	100.0%	159.5%	-59.8%	17.0%		5.5%
14							
15	**45% to UROR = 1.000**						
16	Rate of Return on Rate Base	6.12%	0.88%	17.91%	8.73%		-5.55%
17	UROR	1.000	0.144	2.926	1.426		-0.906
18							
19	Proposed Sales Revenue	$958,724,672	$456,255,944	$247,196,038	$118,264,141		$6,307,104
20							
21	Change in Margin Revenue	$49,400,000	$51,689,498	($1,963,776)	($939,515)		$1,652,112
22	% Change in Margin Revenue	8.2%	18.7%	-1.1%	-1.4%		50.1%
23	% of the Class Change in Margin Revenue	100.0%	104.6%	-4.0%	-1.9%		3.3%
24							
25							
26	Change in Total Revenue	$31,584,406	$44,643,182	($15,948,792)	$6,786,128		$1,549,286
27	% Change in Total Revenue	3.4%	10.8%	-6.1%	6.1%		32.6%
28	% Class Change in Total Revenue	100.0%	141.3%	-50.5%	21.5%		4.9%
29							
30	**40% to UROR = 1.000**						
31	Rate of Return on Rate Base	6.12%	0.41%	18.58%	9.39%		-6.61%
32	UROR	1.000	0.066	3.035	1.534		-1.080
33							
34	Proposed Sales Revenue	$958,724,672	$450,512,666	$250,148,892	$119,676,852		$6,123,536
35							
36	Change in Margin Revenue	$49,400,000	$45,946,220	$989,078	$473,197		$1,468,544
37	% Change in Margin Revenue	8.2%	16.7%	0.5%	0.7%		44.5%
38	% of the Class Change in Margin Revenue	100.0%	93.0%	2.0%	1.0%		3.0%
39							
40							
41	Change in Total Revenue	$31,584,406	$38,899,905	($12,995,939)	$8,198,839		$1,365,718
42	% Change in Total Revenue	3.4%	9.5%	-4.9%	7.4%		28.7%
43	% Class Change in Total Revenue	100.0%	123.2%	-41.1%	26.0%		4.3%

		TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	<<<<<< CONFIDENTIAL >>>>>>	LIGHTING
		(A)	(B)	(C)	(E)	[redacted]	(H)
	35% to UROR = 1.000						
1	Rate of Return on Rate Base	6.12%	-0.07%	19.24%	10.05%		-7.67%
2	UROR	1.000	-0.011	3.143	1.641		-1.253
3							
4	Proposed Sales Revenue	$958,724,672	$444,769,389	$253,101,746	$121,089,564		$5,939,968
5							
6	Change in Margin Revenue	$49,400,000	$40,202,943	$3,941,932	$1,885,909		$1,284,976
7	% Change in Margin Revenue	8.2%	14.6%	2.1%	2.8%		39.0%
8	% of the Class Change in Margin Revenue	100.0%	81.4%	8.0%	3.8%		2.6%
9							
10							
11	Change in Total Revenue	$31,584,406	$33,156,627	($10,043,085)	$9,611,551		$1,182,150
12	% Change in Total Revenue	3.4%	8.1%	-3.8%	8.6%		24.8%
13	% Class Change in Total Revenue	100.0%	105.0%	-31.8%	30.4%		3.7%
14							
15	**33.33% to UROR = 1.000**						
16	Rate of Return on Rate Base	6.12%	-0.23%	19.46%	10.27%		-8.02%
17	UROR	1.000	-0.037	3.179	1.677		-1.311
18							
19	Proposed Sales Revenue	$958,724,672	$442,854,963	$254,086,030	$121,560,468		$5,878,778
20							
21	Change in Margin Revenue	$49,400,000	$38,288,517	$4,926,216	$2,356,813		$1,223,787
22	% Change in Margin Revenue	8.2%	13.9%	2.7%	3.4%		37.1%
23	% of the Class Change in Margin Revenue	100.0%	77.5%	10.0%	4.8%		2.5%
24							
25							
26	Change in Total Revenue	$31,584,406	$31,242,202	($9,058,800)	$10,082,455		$1,120,961
27	% Change in Total Revenue	3.4%	7.6%	-3.4%	9.0%		23.6%
28	% Class Change in Total Revenue	100.0%	98.9%	-28.7%	31.9%		3.5%
29							
30	**30% to UROR = 1.000**						
31	Rate of Return on Rate Base	6.12%	-0.55%	19.91%	10.71%		-8.73%
32	UROR	1.000	-0.089	3.252	1.749		-1.426
33							
34	Proposed Sales Revenue	$958,724,672	$439,026,111	$256,054,599	$122,502,276		$5,756,400
35							
36	Change in Margin Revenue	$49,400,000	$34,459,665	$6,894,785	$3,298,620		$1,101,408
37	% Change in Margin Revenue	8.2%	12.5%	3.7%	4.8%		33.4%
38	% of the Class Change in Margin Revenue	100.0%	69.8%	14.0%	6.7%		2.2%
39							
40							
41	Change in Total Revenue	$31,584,406	$27,413,350	($7,090,231)	$11,024,263		$998,582
42	% Change in Total Revenue	3.4%	6.7%	-2.7%	9.9%		21.0%
43	% Class Change in Total Revenue	100.0%	86.8%	-22.4%	34.9%		3.2%

<<<<<< CONFIDENTIAL >>>>>>

	TOTAL (A)	RESIDENTIAL SERVICE (B)	GENERAL SERVICE (C)	LARGE GENERAL SERVICE (E)	[redacted]	LIGHTING (H)
TEP G-2						
Rate of Return on Rate Base	7.88%	0.92%	19.06%	25.81%		-8.99%
UROR	1.000	0.117	2.418	3.274		-1.141
Proposed Sales Revenue	$1,018,858,790	$469,968,858	$257,179,598	$157,210,163		$5,900,901
Change in Margin Revenue	$109,534,118	$65,402,412	$8,019,784	$38,006,508		$1,245,909
% Change in Margin Revenue	18.1%	23.7%	4.3%	55.5%		37.8%
% of the Class Change in Margin Revenue	100.0%	59.7%	7.3%	34.7%		1.1%
Change in Total Revenue	$91,718,524	$58,356,097	($5,965,232)	$45,732,150		$1,143,083
% Change in Total Revenue	9.9%	14.2%	-2.3%	41.0%		24.0%
% Class Change in Total Revenue	100.0%	63.6%	-6.5%	49.9%		1.2%
37.5% to UROR = 1.000 (LGS=0.0)						
Rate of Return on Rate Base	6.12%	0.17%	19.08%	9.17%		-7.14%
UROR	1.000	0.028	3.117	1.497		(1.166)
Proposed Sales Revenue	$958,724,672	$447,641,027	$252,396,906	$119,203,655		$6,031,752
Change in Margin Revenue	$49,400,000	$43,074,581	$3,237,092	$0		$1,376,760
% Change in Margin Revenue	8.2%	15.6%	1.8%	0.0%		41.7%
% of the Class Change in Margin Revenue	100.0%	87.2%	6.6%	0.0%		2.8%
Change in Total Revenue	$31,584,406	$36,028,266	($10,747,925)	$7,725,642		$1,273,934
% Change in Total Revenue	3.4%	8.8%	-4.1%	6.9%		26.8%
% Class Change in Total Revenue	100.0%	114.1%	-34.0%	24.5%		4.0%
Equal Percentage						
Rate of Return on Rate Base	6.12%	-1.58%	21.40%	12.19%		-13.63%
UROR	1.000	-0.258	3.496	1.991		-2.227
Proposed Sales Revenue	$958,724,672	$426,544,935	$262,695,678	$125,679,517		$4,907,879
Change in Margin Revenue	$49,400,000	$21,978,489	$13,535,864	$6,475,861		$252,887
% Change in Margin Revenue	8.2%	8.0%	7.3%	9.5%		7.7%
% of the Class Change in Margin Revenue	100.0%	44.5%	27.4%	13.1%		0.5%
Change in Total Revenue	$31,584,406	$14,932,174	($449,153)	$14,201,504		$150,061
% Change in Total Revenue	3.4%	3.6%	-0.2%	12.7%		3.2%
% Class Change in Total Revenue	100.0%	47.3%	-1.4%	45.0%		0.5%
% Change in Total Revenue	-1.9%	-1.7%	-5.3%	6.9%		-2.2%
% Class Change in Total Revenue	100.0%	39.6%	78.5%	-43.4%		0.6%

RESIDENTIAL SERVICE RATE R-01

WINTER

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682	
Small	520	500	20	0	0	$10.00	$28.10	$1.30	$0.00	$0.00	$16.40	$3.55	$59.35
Medium	840	500	340	0	0	$10.00	$28.10	$22.17	$0.00	$0.00	$26.49	$5.73	$92.49
Large	1,250	500	500	250	0	$10.00	$28.10	$32.60	$19.53	$0.00	$39.42	$8.53	$138.18
XLg	1,564	500	500	564	0	$10.00	$28.10	$32.60	$44.05	$0.00	$49.32	$10.67	$174.74
AnnAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78

	BILL IMPACTS PROPOSED RATES														
	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		500	1000	>1000			500	1000	>1000						
						$17.00	$0.05669	$0.07670	$0.07670		$0.033801	0.0000%			
														$ Change	% Change
Small	520	500	20	0		$17.00	$28.35	$1.53	$0.00		$17.58	$0.00	$64.46	$5.11	8.6%
Medium	840	500	340	0		$17.00	$28.35	$26.08	$0.00		$28.39	$0.00	$99.82	$7.33	7.9%
Large	1,250	500	500	250		$17.00	$28.35	$38.35	$19.18		$42.25	$0.00	$145.13	$6.95	5.0%
XLg	1,564	500	500	564		$17.00	$28.35	$38.35	$43.26		$52.86	$0.00	$179.82	$5.08	2.9%
AnnAvg	785	500	285	0		$17.00	$28.35	$21.86	$0.00		$26.53	$0.00	$93.74	$6.96	8.0%
ResAvg	785	500	285	0		$17.00	$28.35	$21.86	$0.00		$26.53	$0.00	$93.74	$6.96	8.0%

RESIDENTIAL SERVICE RATE R-01

Summer

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682	
Small	822	500	322	0	0	$10.00	$28.10	$21.64	$0.00	$0.00	$28.86	$5.61	$94.21
Medium	1,384	500	500	384	0	$10.00	$28.10	$33.60	$30.64	$0.00	$48.59	$9.44	$160.37
Large	1,997	500	500	997	0	$10.00	$28.10	$33.60	$79.56	$0.00	$70.12	$13.62	$235.00
XLg	2,430	500	500	1,430	0	$10.00	$28.10	$33.60	$114.11	$0.00	$85.32	$16.57	$287.70
AnnAvg	785	500	285	0	0	$10.00	$28.10	$19.15	$0.00	$0.00	$27.56	$5.35	$90.16
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89

	BILL IMPACTS PROPOSED RATES														
	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill		
		500	1000	>1000			500	1000	>1000						
						$17.00	$0.05669	$0.07670	$0.07670		$0.037325	0.0000%			
														$ Change	% Change
Small	822	500	322	0		$17.00	$28.35	$24.70	$0.00		$30.68	$0.00	$100.73	$6.52	6.9%
Medium	1,384	500	500	384		$17.00	$28.35	$38.35	$29.45		$51.66	$0.00	$164.81	$4.44	2.8%
Large	1,997	500	500	997		$17.00	$28.35	$38.35	$76.47		$74.54	$0.00	$234.71	-$0.29	-0.1%
XLg	2,430	500	500	1,430		$17.00	$28.35	$38.35	$109.68		$90.70	$0.00	$284.08	-$3.62	-1.3%
AnnAvg	785	500	285	0		$17.00	$28.35	$21.86	$0.00		$29.30	$0.00	$96.51	$6.35	7.0%
ResAvg	1,150	500	500	150		$17.00	$28.35	$38.35	$11.51		$42.92	$0.00	$138.13	$6.24	4.7%

Small General Service RATE GS-10

WINTER

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.05700	$0.07900	$0.031532	$0.00682	
Xsm	190	190	0	$15.50	$10.83	$0.00	$5.99	$1.30	$33.62
Small	687	500	187	$15.50	$28.50	$14.77	$21.66	$4.69	$85.12
Medium	1,744	500	1,244	$15.50	$28.50	$98.28	$54.99	$11.89	$209.16
Large	3,680	500	3,180	$15.50	$28.50	$251.22	$116.04	$25.10	$436.36
XLg	5,157	500	4,657	$15.50	$28.50	$367.90	$162.61	$35.17	$609.68
AnnAvg	1,568	500	1,068	$15.50	$28.50	$84.37	$49.44	$10.69	$188.50
SGSAvg	1,340	500	840	$15.50	$28.50	$66.36	$42.25	$9.14	$161.75

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$26.80	$0.06200	$0.08300	$0.033801	0.0000%			
										$ Change	% Change
Xsm	190	190	0	$26.80	$11.78	$0.00	$6.42	$0.00	$45.00	$11.38	33.8%
Small	687	500	187	$26.80	$31.00	$15.52	$23.22	$0.00	$96.54	$11.42	13.4%
Medium	1,744	500	1,244	$26.80	$31.00	$103.25	$58.95	$0.00	$220.00	$10.84	5.2%
Large	3,680	500	3,180	$26.80	$31.00	$263.94	$124.39	$0.00	$446.13	$9.77	2.2%
XLg	5,157	500	4,657	$26.80	$31.00	$386.53	$174.31	$0.00	$618.64	$8.96	1.5%
AnnAvg	1,568	500	1,068	$26.80	$31.00	$88.64	$53.00	$0.00	$199.44	$10.94	5.8%
SGSAvg	1,340	500	840	$26.80	$31.00	$69.72	$45.29	$0.00	$172.81	$11.06	6.8%

Small General Service RATE GS-10

SUMMER

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.07700	$0.09780	$0.035111	$0.00682	
Xsm	216	216	0	$15.50	$16.63	$0.00	$7.58	$1.47	$41.18
Small	882	500	382	$15.50	$38.50	$37.36	$30.97	$6.02	$128.35
Medium	2,354	500	1,854	$15.50	$38.50	$181.32	$82.65	$16.05	$334.02
Large	4,820	500	4,320	$15.50	$38.50	$422.50	$169.24	$32.87	$678.61
XLg	6,690	500	6,190	$15.50	$38.50	$605.38	$234.89	$45.63	$939.90
AnnAvg	1,568	500	1,068	$15.50	$38.50	$104.45	$55.05	$10.69	$224.19
SGSAvg	1,886	500	1,386	$15.50	$38.50	$135.51	$66.21	$12.86	$268.58

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$26.80	$0.07700	$0.09800	$0.037325	0.0000%			
										$ Change	% Change
Xsm	216	216	0	$26.80	$16.63	$0.00	$8.06	$0.00	$51.49	$10.31	25.0%
Small	882	500	382	$26.80	$38.50	$37.44	$32.92	$0.00	$135.66	$7.31	5.7%
Medium	2,354	500	1,854	$26.80	$38.50	$181.69	$87.86	$0.00	$334.85	$0.83	0.2%
Large	4,820	500	4,320	$26.80	$38.50	$423.36	$179.91	$0.00	$668.57	-$10.04	-1.5%
XLg	6,690	500	6,190	$26.80	$38.50	$606.62	$249.70	$0.00	$921.62	-$18.28	-1.9%
AnnAvg	1,568	500	1,068	$26.80	$38.50	$104.67	$58.53	$0.00	$228.50	$4.31	1.9%
SGSAvg	1,886	500	1,386	$26.80	$38.50	$135.79	$70.38	$0.00	$271.47	$2.89	1.1%

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT

RATE DESIGN TESTIMONY

OF

MICHAEL J. MCGARRY, SR.

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 24, 2016

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-15-0322

The Purchase Power and Fuel Adjustment Clause ("PPFAC") Rate Design Direct Testimony of Michael J. McGarry, Sr., of Blue Ridge Consulting Services, Inc. ("Blue Ridge"), provides Staff recommendations concerning two specific rate design proposals proffered by Tucson Electric Power Company ("TEP" or "Company") related to the Company's PPFAC. The first TEP proposed modification seeks to change the PPFAC adjustment to a twelve-month historical average versus the forward-looking methodology currently approved by the Commission. The second proposed modification targets change to the expression of the PPFAC adjustment from cents per kWh to a percentage of the base cost of fuel rate, included in base rates as approved by the Commission in this case.

Based on his analysis, Mr. McGarry finds that the Company has failed to show how these proposals benefit customers, and he believes that implementing the proposals might cause confusion and/or potential cross-subsidization. Staff recommends that the Arizona Corporation Commission ("Commission") reject both the Company's proposed changes to the PPFAC until TEP provides sufficient evidence that these proposals would indeed be beneficial to customers and would not cause confusion or any potential cross-subsidization. Specifically, Staff also recommends that the Commission (1) reject TEP's proposal to change from an annual determination of the PPFAC rate with its forward and true-up components to a twelve-month historical rolling average, and (2) reject TEP's proposal to alter the expression of the PPFAC adjustment to a percentage change of the base cost of fuel rate from the current expression as cents per kWh appearing on customer bills (which is consistent with Staff's position in the UNS Electric, Inc. ("UNS") case, Docket No. E-04204A-15-0142).

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Michael J. McGarry, Sr. I am Senior Technical Consultant with Blue Ridge Consulting Services, Inc. My business address is 114 Knights Ridge Road, Travelers Rest, South Carolina 29690.

BACKGROUND AND QUALIFICATIONS

Q. Are you the same Michael J. McGarry Sr. that proffered testimony in the revenue requirements portion of this case?

A. Yes. My testimony was filed with the Commission on June 3, 2016.

Q. Are your background and qualifications the same here as offered in that filing?

A. Yes. Exhibit MJM-1 attached to that submission is applicable here as well.

Q. Just to reiterate, have you previously testified before the Arizona Corporation Commission ("Commission")?

A. Yes. I have testified in Docket Nos. E-01345A-11-0224, E-04204A-12-0504, and E-01933A-12-0291.

PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am appearing on behalf of the Commission Utilities Division Staff ("Staff").

Q. What is the purpose of the testimony you are presenting?

A. I present the Staff's position with respect to the proposals of Tucson Electric Power Company ("TEP" or "Company") concerning modification of the Purchase Power and Fuel Adjustment Clause ("PPFAC").

Q. Was this testimony and the supporting analyses prepared by you or under your direct supervision?

A. Yes.

Q. Please briefly describe the information you reviewed in preparation for your testimony.

A. I have reviewed the Company's testimony, exhibits, and data request responses provided by the Company to the various parties to this proceeding.

CONTENT OF ATTACHMENTS TO TESTIMONY

Q. Have you attached any exhibits to your testimony?

A. No.

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

Q. Is the Company proposing any changes to the PPFAC?

A. Yes. TEP is requesting a major modification to the PPFAC to (1) implement a monthly change in the rate (which is currently recalculated only annually) and (2) allocate these monthly adjustments to the PPFAC costs on the same percentage basis to all rate classes. As Company Witness Jones states, "The PPFAC charge will be a single percentage adjustment applied to all base rates for all customer classes."[1] In addition, Company Witness Sheehan discusses the Company's proposed change to make the PPFAC a rolling average.

Q. Please briefly explain the PPFAC's current structure in regard to the elements for which modification is proposed.

A. The Company's current PPFAC includes a component called the *base cost of fuel rate* that is established in a base rate case and, therefore, will be set in this case. This *base cost of fuel rate* is fixed until changed by approval of the Commission in a subsequent base rate case.

The current PPFAC also includes two components that are established outside a base rate case: the *forward component* and the *true-up component*. The *forward component* is set annually in a PPFAC filing made by the Company and as ordered by the Commission. The last PPFAC filed by TEP was February 1, 2016. This *forward component* is a projection of fuel and purchased power costs for the upcoming 12-month period, during which the forward component is expected to be in effect. It is calculated using a sophisticated production-modeling program called AuroraXMP.

The *true-up component* is, as its designation suggests, the difference between the previous 12-month *forecast component* and the *actual* purchased power and fuel costs the Company incurred during that previous 12-month period.

Through this PPFAC structure that has been in place, the Company is currently allowed to recover the following purchased power and fuel-related costs from customers:

[1] Direct Testimony of Craig A. Jones at page 77, lines 3-8.

Component	Authorized Recovery (¢ per kWh)[2]
Base Cost of Fuel	3.2335
Forward Component	0.2782
True-up	(0.1281)
Average Total Rate	3.3836

TEP Proposal 1: PPFAC Frequency Change

Q. Please explain the details of the Company's proposal.

A. As mentioned, the first of the Company's PPFAC proposals is to alter the frequency by which the PPFAC rate is changed. The frequency change is from annually to monthly. This change would remove the forward component's 12-month projection of costs in favor of calculating a historical 12-month rolling average. Company Witness Sheehan states in his testimony,

> TEP is proposing to modify its PPFAC to consist of a base rate and a PPFAC percentage rate. The sum of the base rate and the PPFAC percentage rate will be derived by using the prior twelve month's weighted average fuel costs, net of short-term wholesale revenues. Each month the calculation will fluctuate based upon actual net costs of the prior 12-monthly period.[3]

Witness Sheehan then states that the base rate of fuel costs will remain fixed and only the PPFAC percentage will change each month.

Q. Does the Company provide justification for this change?

A. In my view, the Company offers only limited and insufficient justification for this major change. The Company states that the reason for the proposed change is to smooth the volatility of fuel costs for customers.[4] Witness Sheehan notes that this type of rolling average

[2] TEP PPFAC filing dated February 1, 2016. Approved by Commission Order dated April 22, 2016. Rates effective May 1, 2016.
[3] Direct Testimony of Michael Sheehan – page 42, Lines 8-13.
[4] Ibid. at page 42, lines 25-26.

is utilized in TEP's sister companies, UNS Electric and UNS Gas. He also notes that TEP is moving toward a more natural gas-based generation mix and away from coal, costs of which have traditionally been very stable. He states as justification that the annual reset of PPFAC rate has created a couple of instances of "significant bill impact."[5] Witness Sheehan proposes that the transition to the twelve-month rolling average combined with effective hedging will lower PPFAC volatility and smooth potential bill impacts.[6]

Q. Does the Company provide recast comparison of previous fuel costs to show what the impact of its proposal would have been during the test year (or any other period)?

A. No. The Company provides no additional analysis or comparisons whatsoever. It merely states without substantiation that volatility will decrease.

Q. Are there any other factors to consider in the frequency change?

A. Yes. The current 12-month projection may anticipate expected changes that may not be part of the historical trend. Therefore, if the PPFAC rate ignores any forecast and takes into account only historical trend, volatility may still be a factor. This is particularly true if the Commission were to adopt the 12 month rolling average as proposed. Customers would be used to a single rate change each April/May and now that change is monthly. This potentially could cause customer to question why rates are changing frequently.

Q. What is your opinion of the Company's proposal to go from an annual rate to monthly rolling average?

A. The Company has not satisfactorily demonstrated its presumed reduction of volatility, and potential unintended consequences of changing the methodology on customers. There is insufficient analysis to determine whether moving to a monthly rolling average would be

[5] Direct testimony of Michael Sheehan at page 43, lines 1-3
[6] Ibid at lines 3-5

beneficial to customers or create additional confusion. Therefore, until the Company can demonstrate its claims regarding volatility reduction with the proposed change and impacts on customers, it is my opinion that the Commission should reject the Company's proposal.

TEP Proposal 2: PPFAC Allocation Change

Q. Please describe the Company's other proposed PPFAC change to allocation of PPFAC rate from an incremental increase/decrease in cents per kWh to a percentage-based increase/decrease to each customer class?

A. As I mentioned previously, the Company intends to modify the allocation of the increase or decrease to the monthly recalculated PPFAC rate from cents per kWh to a single percentage basis across all customer classes. Company Witness Jones provides one short statement explaining the Company's position.[7] As an example, if the PPFAC were calculated resulting in a 0.5 percent increase, compared to the existing cost of fuel base rate approved in this case, then each customer class (i.e., residential, small commercial, and LPS) would see the same 0.5 percent adjustment as a PPFAC adder.[8] As explained earlier, the PPFAC adder is currently calculated on a cents per kWh basis and then added to the customer's bill. Witness Jones states that the percentage method "better aligns the changes in fuel costs with each rate class' base fuel costs."[9]

Q. Beyond the Company's testimony, was there any analysis provided that supported the Company's claim or showed how customers would benefit from the proposed rate design allocation change?

A. No. The Company's statement was left unsubstantiated

[7] Direct Testimony of Craig Jones at page 77, lines 10-18.
[8] Ibid at lines 17-18
[9] Ibid at line 12-13

Q. Do you have an opinion concerning this proposal?

A. Yes. Consistent with Staff's position in the UNS case, Docket No. E-04204A-15-0142, I recommend that the PPFAC remain as a calculation of cents per kWh. There is no evidence to suggest that customers would benefit from changing to the Company's proposed plan.

Q. Please summarize Staff's rate design recommendations for the PPFAC?

A. Staff recommends that the Commission reject the Company's proposed changes to PPFAC until such time that the Company provides sufficient evidence that these proposals would be beneficial to customers and not cause confusion or any potential cross-subsidization. Specifically, Staff recommends that the Commission reject the Company's proposal:

- To move from an annual determination of the PPFAC rate, with its forward and true-up components, to a twelve-month historical rolling average, and
- To change how these monthly adjustments to the PPFAC are expressed from a cents per kWh basis on customer bills to a percentage change that would be applied equally to all customer classes.

Q. Does this conclude your PPFAC Rate Design Testimony?

A. Yes. It does.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

PUBLIC UTILITIES MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 24, 2016

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DOCKET NOS. E-01933A-15-0322, E-01933A-15-0239

My testimony addresses Tucson Electric Power Company's ("TEP" or "Company") proposed Residential Community Solar program ("RCS").

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Robert G. Gray. I am a Public Utilities Manager employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Manager.

A. In my capacity as a Public Utilities Manager, I conduct analysis and provide recommendations to the Commission on a variety of electricity, natural gas, and water/wastewater matters as well as fulfilling supervisory responsibilities. A copy of my resume is attached as Exhibit RGG-1.

Q. Are you the same Robert G. Gray who filed Direct Testimony on March 11, 2016 and Responsive Testimony on March 28, 2016 in Docket No. E-01933A-15-0239 as well as prepared the Staff Report filed on April 19, 2016 regarding Tucson Electric Power Company's ("TEP") proposed 2016 REST plan?

A. Yes. The Direct and Responsive Testimony were filed to address the TEP-Owned Residential Solar ("TORS") program and the Residential Community Solar ("RCS") program as well as the question of whether the RCS program, where generation is not sited on a given customer's premise, should be considered distributed generation. I also testified in regard to these matters at the hearing on April 7, 2016 at the Commission's Tucson office. The Staff Report addressed the balance of TEP's 2016 REST plan proposal and the recommendations contained therein were approved by the Commission in Decision No. 75560 (May 13, 2016).

Q. What is the scope of your testimony in this case?

A. Via the April 6, 2016 Procedural Order, the Docket addressing TEP's proposed 2016 REST plan, E-01933A-15-0239, was consolidated with TEP's general rate case docket, E-01933A-15-0322. The April 6, 2016 Procedural Order indicated that the consolidation would preserve the ability to set the RCS tariff and rate in the rate case. It is Staff's general understanding that the April hearing on these programs and the pending order resulting from that hearing will address whether the programs are in the public interest. To the extent that the programs are deemed in the public interest the tariff and rates would then be set in the rate case proceeding. My testimony introduces the issue of setting the RCS tariff and rate in the rate case proceeding and discusses related issues.

RESIDENTIAL COMMUNITY SOLAR PROGRAM

Q. Did Staff recommend approval of the RCS program?

A. Yes. Staff recommended approval of the RCS program, subject to a number of conditions.

Q. What recommendations did Staff make in your Direct and Responsive Testimony and at the hearing regarding setting the RCS tariff and rate?

A. Staff made the following recommendations regarding the RCS tariff and rate:

1. Staff recommended that the RCS program include a third party owned component where TEP would solicit the same amount of generation capacity from a third party owned supplier at the same time as TEP implements utility-owned generation for the RCS program.

2. Staff further recommended that rather than having the 15 percent provision for the RCS program, TEP adjust the customer's charge each following year for any movement in the customer's average monthly usage higher or lower in the previous.

3. Staff further recommends that the RCS rate be cost-of-service based to specifically reflect the cost of serving the customers on the RCS program.

4. Staff further recommended that the solar generation facilities built to serve RCS program demand be newly constructed for the RCS program and not a repurposing of existing solar generation.

Q. Has a cost-of-service based rate to the RCS program been identified with sufficient specificity at this time?

A. No. At this time TEP has not provided a detailed cost-of-service analysis specific to RCS customers would be. Attached as Exhibit RGG-2 are three data request responses from TEP giving indications that the facility to serve RCS customers is still early in development and that costs in general are only estimates at this time. Staff is still reviewing information provided by TEP and intends to recommend a rate as part of Staff's surrebuttal testimony in this proceeding. Staff encourages TEP to provide a detailed cost-of-service analysis and resulting rate for RCS customers in its Rebuttal Testimony. Staff is willing to consider a weighted average cost from a recent vintage of TEP's utility owned PV solar facilities as a proxy in lieu of the specific facility dedicated to RSC if its costs are not known in time for this rate case. That information was discussed at length by TEP and Staff in the hearing in Docket No. E-00000j-14-0023

Q. Does this conclude Staff's direct testimony?

A. Yes, it does.

RESUME

ROBERT G. GRAY

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utility Manager (February 2016 – present), Executive Consultant, Manager (December 2015 – February 2016), Executive Consultant III (November 2007 – December 2015), Public Utility Analyst V (October 2001 – November 2007), Senior Economist (August 1997 – October 2001), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses on a variety of natural gas issues in Arizona, including gas procurement, rate design, interstate pipeline issues, revenue decoupling, energy conservation, low income issues, customer services issues, special contracts, various tariff matters, and other natural gas issues. Conduct economic and policy analyses on a variety of electricity issues in Arizona, including power plant and transmission line siting cases, energy efficiency, renewable energy standards, rate design, time-of-use service, and low income issues. Conduct economic and policy analysis on water and wastewater issues. Supervise assigned Staff to ensure timely completion of assigned tasks. Prepare recommendations and present written and oral testimony before the Commission and organize workshops and other proceedings on various utility industry issues. Represent the ACC in natural gas and electric proceedings at various state of Arizona proceedings, the Federal Energy Regulatory Commission, the North American Energy Standards Board, and on the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Gas, including serving as a past Vice-Chair and Chair of the NARUC Staff Subcommittee on Gas.

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Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-01551A-06-0107), Arizona Corporation Commission, May 16, 2006.

Staff Report on UNS Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-04204A-06-0627), Arizona Corporation Commission, January 30, 2007.

Staff Review of UNS Electric 2008 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-07-0593), Arizona Corporation Commission, March 25, 2008.

Staff Report on Semstream Arizona Propane, Payson Division Bankruptcy, Reorganization, and other issues, Arizona Corporation Commission, June 6, 2008.

Staff Review of UNS Electric 2009 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-07-0593), Arizona Corporation Commission, November 26, 2008.

Staff Review of Tucson Electric Power 2009 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-07-0594), Arizona Corporation Commission, November 26, 2008.

Staff Report for Arizona Water Company and Global Water Resources LLC's Consolidated Docket Addressing Numerous Requests for Extensions of Certificates of Convenience and Necessity for Water and Wastewater Service as Well as the Transfer of Assets, (Docket No. W01445A-06-0199, etc.), Arizona Corporation Commission, May 10, 2009.

Staff Review of UNS Electric 2010 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-09-0347), Arizona Corporation Commission, January 5, 2010.

Staff Review of Tucson Electric Power 2010 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-09-0340), Arizona Corporation Commission, January 5, 2010.

Staff Review of UNS Electric 2011 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-10-0265), Arizona Corporation Commission, November 8, 2010.

Staff Review of Tucson Electric Power 2011 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-10-0266), Arizona Corporation Commission, November 9, 2010.

Staff Review of UNS Electric 2012 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-11-0267), Arizona Corporation Commission, October 25, 2011.

Staff Review of Tucson Electric Power 2012 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-11-0269), Arizona Corporation Commission, October 25, 2011.

Staff Review of UNS Electric 2013 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-12-0297), Arizona Corporation Commission, October 18, 2012.

Staff Review of Tucson Electric Power 2013 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-12-0296), Arizona Corporation Commission, October 18, 2012.

Staff Review of UNS Electric 2014 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-13-0225), Arizona Corporation Commission, September 30, 2013.

Staff Review of Tucson Electric Power 2014 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-13-0224), Arizona Corporation Commission, September 30, 2013.

Staff Review of UNS Electric 2015 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-14-0249), November 3, 2014.

Staff Review of Tucson Electric Power 2015 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-14-0248), November 3, 2014.

Renewable Energy Standard and Tariff Rulemaking (Docket No. RE-00000C-14-0112), Arizona Corporation Commission, 2014.

(with other Staff members) Arizona Corporation Commission Comments on the Draft Clean Power Plan, United States Environmental Protection Agency, (EPA Docket Number EPA-HQ-OAR-2013-0602), December 1, 2014.

Staff Review of UNS Electric 2016 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-04204A-15-0233), November 24, 2015.

(with other Staff members) Arizona Corporation Commission Comments on the Clean Power Plan Federal Plan, Model Rules, and Clean Energy Incentive Program, United States Environmental Protection Agency, (EPA Docket Number EPA-HQ-OAR-2015-0199), January 21, 2016.

Staff Review of Tucson Electric Power 2016 Renewable Energy Standard Tariff and Implementation Plan, (Docket No. E-01933A-15-0239), March 11, 2016.

Education

B.A. Geography, University of Minnesota-Duluth (1988)
M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition
1997, 1998	NARUC Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference

1999 – 2007, 2010, 2012 NARUC Summer Committee Meetings
2001 Center for Public Utilities Workshop on Risk Management in Gas Purchasing
2003-2008 NARUC Winter Committee Meetings
2004-2007 NARUC Annual Convention

Memberships

NARUC – Staff Subcommittee on Gas – member, 1998 - present
NARUC – Staff Subcommittee on Gas – Vice-Chair - 2002 - 2004
NARUC – Staff Subcommittee on Gas – Chair - 2005 - 2007
Michigan State Institute for Public Utilities – NARUC Advisory Committee – 2005-2007
NARUC – North American Energy Standards Board Advisory Council – 2006 - present
NARUC – DOE LNG Partnership – 2003 – present
North American Energy Standards Board – Board of Directors – 2014 - present
North American Energy Standards Board – Executive Committee, Retail Energy Quadrant, Retail Electric End Users/Public Agencies Segment – 2014 - present

STF 25.5

RCS Program: The following questions refer to the proposed residential community solar program in TEP's 2016 REST plan.

a. Has a site been selected for the 5 MW facility for this program?

b. If yes, has any design, permitting, or construction begun?

c. What is the expected completion date?

RESPONSE:

a. No, although several sites are under consideration.

b. N/A

c. The expected COD will be approximately 12 months after approval of the program.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S TWENTY-FIFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
June 10, 2016

STF 25.7

RCS Program: In response to Staff 3.6(c), TEP indicated that the $10,000,000 cost was an estimate based on 5 MW at $2.00 per watt.

a. Does TEP have actual cost data to support the $2.00 per watt cost?

b. If so, please break down that cost into components for the land, equipment, and installation.

c. In the TEP 2016 REST docket, TEP indicated the cost for this program is expected to be approximately $1.60 per watt. Is the actual cost closer to the $1.60 per watt or $2.00 per watt or some other number?

RESPONSE:

a./c. The $10,000,000 estimate is a budgeting estimate, not an actual cost of development estimate. Similar to engineering and design for renewable substation construction, the Company provides for contingencies for internal budgeting purposes only. This is to ensure that the Company has sufficient capital available in the event of an unforeseen development expense.

The Company's actual experience with utility scale development remains around $1.60 per watt. This is consistent with the Company's response to Staff's 1st set of data requests in the Company's 2016 REST Plan filing, dated August 24, 2015.

b. All values are approximate and subject to change depending on market conditions.

Modules - $0.65/watt

Inverters - $0.25/watt

Labor - $0.30/watt

Balance of System - $0.25/watt

Land/Prep - $0.15/watt

c. See part a, above.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

STF 25.8

RCS Program: In the TEP 2016 REST Plan, TEP proposed Rider R-17 detailing the rates for the RCS Program.

a. What is the proposed tariff rate per kW (from the TEP 2016 REST Plan) based on?

b. How did TEP arrive at that tariff rate?

c. Is the rate based on actual cost of service data specific to the proposed program?

   i. If not, what would the rate be if based on cost of service data specific to the proposed program?

   ii. If cost of service data specific to the proposed program is not available at this time, when would such data be available?

RESPONSE:

a.-b. Consistent with the Company's response to Staff data request STF 1.35 for the Company's REST Implementation Plan, the tariff rate is based on the previously approved $16.50 per watt per month rate for the residential (rooftop) program, plus an adder of $1.00 per watt per month to further reduce the cost shift to non-participating customers. The $1.00 per kW adder represents approximately $6.00 per month and approximates the cost a consumer would pay for increased homeowners insurance, as well as possible increases in future property taxes and necessary roof repairs to participate in the customer-sited program.

c. The Company used the traditional cost of service study to identify the revenue associated with a conventional residential customer. Previously that revenue requirement was around $93 per month for a customer that consumed 11,400 kWh annually. This customer's equivalent "net-zero" solar system would be 6 kW, and therefore a rate of $16.50 per kW per month was calculated for the tariff rate. As stated above in STF 25.3, depending on the final revenue requirement approved in this case, based on the cost of service studies, will most likely result in a final tariff rate between $18.50-$19.50 per kW per month. This rate will be recalculated to be consistent with the final approved rates.

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT RATE DESIGN

TESTIMONY

OF

MATT CONNOLLY

EXECUTIVE CONSULTANT II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 24, 2016

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-15-0322 AND E-01933A-15-0239

Staff's testimony contains analysis and recommendations regarding Tucson Electric Power Company's ("TEP") request for the implementation of an optional Prepay Metering Program and its request for the elimination of certain compliance requirements.

Regarding TEP's proposed Prepay Metering Program, the Arizona Corporation Commission Utilities Division ("Staff") recommends the following:

- The Program be approved as a Pilot Program for at least twenty-four months.
- The Program exclude customers relying on an electrical device for medical survival.
- The Program not be included in TEP's Energy Efficiency portfolio.
- TEP receive a waiver from providing a written disconnect notice as required under the Arizona Administrative Code ("A.A.C.") § R14-2-211(D) for the purposes of this Program.
- TEP Lifeline customers be allowed to participate in the Program.
- TEP modify its Prepay Service Agreement in accordance with Staff's recommendations and file it with Staff for analysis, review and approval prior to the implementation of the Program.
- The rates and charges may need to be revised, pending Staff review.

Regarding TEP's request to be relieved of certain compliance requirements, Staff recommends the following:

- The following Retail Electric Competition Rules be suspended until further order of the Commission:
    - Systems Benefit Charge Filing (R14-2-1608 (A))
    - Annual Electric Competition Filing (R14-2-1613 (A) and (B))
    - Annual Consumer Information Label (R14-2-1617 (A), (C), (D) and (G))
    - Annual Disclosure Report (R14-2-1617 (G) and (E))

- TEP continue to file an Annual Update to its Electric Load Curtailment Plan as required by Decision No. 66034.

- TEP be relieved of the requirement that it file a report every (5) five years listing potential improvements to Springerville Units 1 and 2 that reduce emissions and costs associated with the improvements as ordered by Decision No. 65347, dated November 1, 2002.

- TEP be relieved of the requirement that it file an Annual Cost Containment Report required initially by Decision No. 59594.
- TEP continue to file an Annual Estimated First or Final Bill Report as required by Decision No. 64180.

- TEP be relieved of the requirement that it file a Full Decoupling Report in connection with its Lost Fixed Cost Recovery ("LFCR") annual adjustment as required by Decision No. 73912.

- TEP be relieved of the requirement that it file an Annual Letter of TEP's Code of Conduct as required by Decision No. 62767.

- TEP be relieved of the requirement that it file an Annual Summer Preparedness Report for the Cyprus Sierrita substation Certificate of Environmental Compatibility ("CEC") as required by Decision No. 69680.

- TEP be relieved of the requirement that it file an Annual Sign Replacement Report for the Cyprus Sierrita substation CEC as required by Decision No. 69680.

- UNS Electric continue to file an Annual Self-Certification Letter identifying progress made with the conditions set out in the CEC for the Vail substation to the Valencia substation as required by Decision No. 71282.

- TEP be relieved of the requirement that it file an Annual Self-Certification Letter identifying which conditions have been met in the CEC authorizing construction of a double circuit, 345 kV transmission line running from TEP's South 345 kV Substation to a proposed TEP Gateway Substation in Nogales, Arizona in Santa Cruz County with a 115 kV interconnection to the 115 kV Valencia Substation and 345 kV line to the international border as required by Decision No. 64536.

- TEP be relieved of the requirement to develop a data base of existing renewable energy resources within its service area within six months from the effective date (June 1, 1994) of Decision No. 58643, revise it annually and submit to Staff each year as part of the historical data filings required under Integrated Resource Planning rules (R14-2-703 (A) and (B)).

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Matt Connolly. I am an Executive Consultant II employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant II.

A. I provide information, analysis and support to Staff on utility-related filings, applications and a variety of other utility-related matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Arts Degree in History from Westminster College in Fulton, Missouri.

Since joining the Commission in June of 2014, I have participated in numerous cases and regulatory proceedings involving electric, gas, water, and telecommunication utilities. I have testified on matters involving telecommunications applications for Certificates of Convenience and Necessity and a Rulemaking. Additionally, I have attended utility-related seminars sponsored by the National Association of Regulatory Utility Commissioners ("NARUC") and the National Regulatory Research Institute ("NRRI") on a variety of utility regulation matters.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01933A-15-0322?

A. Yes.

Q. What is the scope of your testimony in this case?

A. I am presenting Staff's analysis and recommendations in response to Tucson Electric Power Company's ("TEP") request for the implementation of an optional Prepay Metering Program ("Program"). I am also presenting Staff's analysis and recommendations in response to TEP's request to be relieved of a number of compliance items.

THE COMPANY REQUESTED PREPAY PROGRAM

Q. Please describe TEP's proposed Prepay Program.

A. TEP is proposing to offer an optional Prepay Metering Program as a permanent service offering for customers who want to pay in advance for their electrical service. As described in the filed testimony of TEP's witness, Ms. Denise Smith, the TEP Program will be available to all residential customers as a stand-alone tariff except for those who are dependent upon electrical devices for health-related reasons. It proposes to offer the benefits of waivers of a service security deposit and reconnection/disconnection field service charges; no late payment fees for non-payment; access to daily energy use information in order to understand and control energy usage; TEP-provided energy efficiency tips and educational materials, and access to customizable low balance alerts to aid in the assistance of energy use management and payment scheduling.

TEP states in the testimony of Mr. Craig Jones, the Prepay rate is a blended per kWh rate that is based on the weighted average of the two energy rate tiers for the Residential Electric Service Tariff (R-01). The first rate of $0.064000 will be assessed for the first twenty (20) kWh per day both in summer and winter and a second rate of $0.079000 will be applied to kWh over 20.[1] The Program will also have a $20 monthly basic service charge plus a $2 fee to

[1] In response to Staff DRs STF 17.30 and 17.31, TEP explains that the second Prepay tier was created as residential customers who use over 600 kWh per month on the Program would have a lower monthly bill if just a single Prepay tier were in place. The TEP Residential R-01 tariff indicates an energy rate of $0.079100 for over 500 kWhs per month.

cover the cost of the new cellular system required by the meter to facilitate on demand disconnection and reconnection, a $1 fee for the partial recovery of the cost of the required customer premise meter and a $2 fee for the cost of upgrading the data management system and billing interface required to provide the Prepay service. A total charge of $25.00 divided by a thirty day period results in an approximate per day service charge of $0.84. According to the proposed Prepay Service Agreement and in response to Staff DR STF 17.53, a customer will be required to pay at least $20.00 to establish a Program balance.

In addition, TEP proposes to adopt the following customer protections: TEP will provide all Program customers a Prepay Service Agreement and Welcome Packet that includes information about energy efficiency opportunities; will not enroll any customer who has not acknowledged they have read the Prepay Service Agreement[2]; will not enroll in Prepay any customers who have significant medical issues or require the assistance of electrically powered medical devices; will deliver low balance/disconnect alerts via phone, text or email; will only disconnect a customer after a four (4) hour grace period following a disconnect alert[3]; will not disconnect a customer during an extreme weather event or during non-business hours[4]; and will document disconnections and provide documentation of disconnection history to limited-income customers to support bill assistance applications.

TEP will also include in the Program a 75/25 payment option which will enable a Prepay customer the opportunity to pay off an outstanding balance. For customers who select this option, 75 percent of their payment will be applied to their prepaid energy balance and 25

[2] In response to Staff DR STF 17.21, TEP indicated that acknowledgement will occur consistent with the selected enrollment channel. Customers enrolling via the web-based access will be prompted to select and click an acknowledgment prompt after being presented with an electronic copy of the terms and conditions. Customers enrolling over the telephone will be read an abridged version of the terms and conditions and asked for a verbal acknowledgement which will be documented by the customer service representative. In all cases a customer will receive a mailed copy delivered to their service address.

[3] In response to Staff DR STF 17.52, TEP indicates the Company is in the bid process for a payment solutions vendor and anticipates most payment options to be posted within 30 minutes of receipt.

[4] In response to Staff DR STF 17.24, TEP defines an extreme weather event as a day when the high temperature is expected to hit 110 degrees or, in cold climates, not to exceed 32 degrees.

percent will be applied to the reduction of the outstanding balance. For example, as described in the response to Data Request ("DR") STF 17.18, a customer who has an average $2.50 daily energy use will be required to pay an additional $0.83 daily which would be applied toward the outstanding balance. Any customer who has an outstanding balance and who wishes to select the Program will either have to enroll in this option or pay off their outstanding balance in full before they can be admitted to the Program.

As described in response to Staff DR STF 17.34, in order for a customer to participate in the Program, TEP must install a special meter with 2-way communication capability that includes the ability for remote disconnect and reconnect.[5] TEP also plans to enhance and upgrade the interface between its Meter Data Management ("MDM") hub and its Customer Care and Billing ("CC&B") system in order to provide customers with daily energy usage and account balance data. In response to DR STF 17.19, TEP stated that several of the upgrades required for the MDM system are slated for completion in late first quarter of 2017. Customizations of the CC&B system unique to the Program will only take place upon Commission approval of the Program which will take approximately twelve (12) months to complete. TEP also plans to introduce a new mobile application to allow customers to manage payments, receive outage notifications and view past and present usage. However, as described in the response to Staff DR STF 17.20, a customer without a smartphone will, in the alternative, be able to make prepayments and access information via TEP's online account manager or via telephonic Interactive Voice Response ("IVR") or at a participating retail location (the latter subject to a transaction fee).

[5] In response to Staff DR STF 17.33, if the customer resides in a single unit of a multi-unit dwelling serviced by a single meter, the customer would not be eligible for the Program.

Q. TEP is proposing to offer its Program as a permanent service offering. Does Staff agree with this decision?

A. No. Staff believes the Program should be offered as a Pilot. TEP is proposing a third-party evaluation of the Program not less than 24 months after (i) the launch of customer enrollment, and (ii) two successive "high bill" seasons. In response to Staff DR STF 17.26, TEP will use the following criteria to judge the success of the Program when filtered for the impacts of disconnection and participation in other Energy Efficiency ("EE") programs: does the program result in a customer reduction of energy consumption; are participating customers satisfied with their experience and whether customers report a feeling of empowerment and in control of their energy usage and spending when assessed against other customers not in the Program. While Staff has no issues with the proposed criteria, Staff is of the opinion that measurement using these criteria would be better served to discover the value and interest in the program before it becomes permanent. Additionally, in response to Staff DR STF 17.37, TEP is projecting up to 20 percent of its customers may elect to participate in the Program and is a "popular option for many customers with satisfaction typically very high." However, as TEP admits it is relying on the experience of other utilities, introducing its own Program as a pilot will provide the opportunity to validate these assumptions. Finally, while the rates and charges for this Program are based on calculations derived from the TEP Residential R-01 offering, they are not derived from the actual experience for a TEP Prepay program. Twenty-four months of Pilot time will serve to help ground rates and charges in reality and, as this is not an option TEP is considering now with the Program, perhaps help TEP to broaden the availability of the Program to such other options as Time of Use customers.

Q. Does Staff believe it is appropriate to exclude customers from the Program who are dependent upon electrical devices for health-related reasons?

A. Yes. TEP stated in its response to DR STF 17.16 that it lacks the medical expertise to evaluate on a case-by-case basis the appropriateness of the Program for customers in this situation. Staff believes a customer relying on an electrical device for medical survival should not be subject to possible disconnect due to a zero bank balance.

Q. TEP has indicated it will be including the Program as part of its portfolio of EE programs to encourage customer energy conservation and count the Program towards meeting the EE Standard. Does Staff believe such inclusion is appropriate?

A. No. In response to Staff Data Request STF 17.145, TEP states that prepay programs in other jurisdictions have demonstrated reduction in energy consumption by participants such as Salt River Project's M-Power program which recorded a 12 percent effect and Arizona Public Service's prepay pilot program which saw a 7.16 percent energy savings. Staff is not convinced any program that is designed to cut off power due to the customer's inability to pay is in accordance with the Arizona Administrative Code ("A.A.C.") § R14-2-2401(17) definition of EE which means "the production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end-use customers." While TEP has indicated it will provide EE tips and a Welcome Packet with educational information about EE opportunities, this does not mean that a customer will implement any of the provided ideas.

Further, the Program is simply a billing option. Any reduction in energy use is an ancillary result and entirely in question at this time. Additionally, a Demand Side Management ("DSM") program must be shown to be cost effective and costs associated with a DSM program can be collected through the Demand Side Management Adjustment Charge

("DSMAC"). This Program has not been shown to be cost effective and TEP is planning to collect the costs for this proposed Program from those customers who participate in the Program.

Q. TEP is requesting a waiver from A.C.C. R14-2-211 as part of its Program. Does Staff believe such a request is appropriate?

A. Yes. R14-2-211 rules address Termination of Service. Specifically, TEP is requesting that a Prepay customer not receive a written disconnect notice as required under R14-2-211(D). TEP is requesting that in lieu of a written notice, customers would receive a No Credit Disconnect alert via their choice of communications (phone, email or text) no less than four hours before the actual disconnection. Designed as such, TEP's proposed Program will function in "real time". R14-2-211(E)(1) requires a written notice to be given to the customer at least five days in advance of termination. Clearly, this is not functional under the proposed Program. As TEP is not requesting to eliminate customer notices but simply to replace them with a notice type more in line with the technological tools proposed for this Program, Staff recommends the Commission grant TEP's waiver request in this instance.

Q. In response to Staff DR STF 17.38, TEP provided a copy of its proposed Prepay Service Agreement ("Agreement"). After review of this document, does Staff have any requested changes?

A. Yes. Staff believes the following modifications to the Agreement should be made by TEP for the following section numbers:

9. Eliminate this section. Staff believes TEP should allow Lifeline customers to participate in its Program.

13. TEP indicates in testimony that it will deliver balance alerts to customers at customer-selected thresholds and a daily alert when a prefunded energy balance falls to $19 and below. This information should be added to this section to help clarify when an alert will be delivered.

20. Eliminate this section. A Prepay account closed to nonpayment is an account with no balance of funds. Therefore, there will be no outstanding balance.

Factoring in Staff's suggested changes to the Agreement, along with a number of typos and grammatical errors in the proposed Agreement, Staff requests that prior to the implementation of the Program, TEP submit its Agreement to Staff for final analysis, review and approval.

Q. In Section 3 of the Agreement, TEP indicates that to "activate a Prepay account, the customer must pay a required nonrefundable Service Establishment Fee". Does Staff believe this is appropriate?

A. Not at this time. Staff is concerned the "required nonrefundable Service Establishment Fee" may be a possible substitute for a service security deposit. Staff also notes there is no value assigned to this fee, it does not appear to be listed in the proposed Tariff nor is there any cost explanation for why this fee would be assessed on Prepay customers.

Q. While the initial testimony of Ms. Denise Smith stated "The Prepay tariff is a stand-alone tariff exclusive of certain other pricing options", TEP has indicated to Staff that it would be willing to create a Prepay tariff that would include Lifeline customers by dividing the Lifeline rate by (30) thirty days. Does Staff agree with this proposal?

A. Yes. Prepay programs across all industries are often selected by low-income end users as a convenient way to avoid security deposits. TEP customers receiving a Lifeline credit should have the opportunity to use the Program without having to move off the Lifeline program.

Q. Is Staff in agreement with the rates and charges included in TEP's proposed Prepay tariff?

A. No. Staff cannot support the proposed rates and charges at this time. Staff is still reviewing the rates and charges and reserves the right to address them in surrebuttal testimony.

Q. TEP has indicated in its response to Staff DR STF 17.20 that it has requested, in this Rate Case, the "partial socialization of credit and convenience fees to achieve a $1 per transaction fee for the payments rate for credit card transactions and the convenience of local retail channels." Does Staff agree with this effort in regards to its effect on Prepay customers?

A. No. Staff's response to the socialization request is clearly spelled out on pages 33 and 34 of the Redacted Direct Testimony of Donna H. Mullinax, filed June 3, 2016. However, as a $3.50 per transaction fee can be excessive and a burden on a Prepay customer, Staff believes TEP should clearly indicate in its Prepay Service Agreement that a customer could be subject to an additional per payment fee of up to whatever the highest convenience fee is in place. The Agreement should be periodically updated to reflect this amount as it, or if it, changes.

COMPANY REQUESTED COMPLIANCE ITEMS TO BE ELIMINATED

Q. TEP has requested to be relieved of compliance with certain Retail Electric Competition Rules. Does Staff believe TEP should be granted this request?

A. Yes. TEP has requested to be relieved of compliance with the following Retail Electric Competition Rules:

- Systems Benefit Charge Filing (R14-2-1608 (A))
- Annual Electric Competition Filing (R14-2-1613 (A) and (B))
- Annual Consumer Information Label (R14-2-1617 (A), (C), (D) and (G))
- Annual Disclosure Report (R14-2-1617 (G) and (E))

TEP based its request on the fact that these rules are not relevant as there is no electric competition in Arizona at this time and significant portions of the ACC Retail Electric Competition Rules were vacated by the "Phelps Dodge decision":[6]

Staff recommends that the requirements for the filings listed above be suspended for TEP until further order of the Commission.

Q. TEP has requested to be relieved of the requirement that it file an Annual Update to its Electric Load Curtailment Plan as required by Decision No. 66034, dated July 3, 2003. Does Staff believe TEP should be granted this request?

A. No. TEP states this filing should not be necessary unless the Plan is being modified. An Electric Load Curtailment Plan is set in place by Commission Rule R14-2-208(E) in order for the Commission to stay informed of an electric utility's procedures for handling severe supply shortages or service curtailments in the event of an emergency. While Staff has no reason to

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[6] Phelps Dodge Corp v. Arizona Electric Power Cooperative, No. 1 CA-CV 01-0068, 2004 WL 117253 (Ariz. Ct. App. 27, 2004)

doubt that TEP, as it indicated to Staff, would file an update in the event of a change to its Plan, Staff is of the opinion that the Commission should always be in a position to be able to refer to the latest information in the event of an emergency, even if that information has not recently changed significantly.

However, during its analysis of this TEP request, Staff noted that TEP was filing an annual report indicating that no curtailments had occurred in the previous year. In Decision No. 66034, TEP was ordered to file a detailed curtailment report the next business day after a curtailment had occurred and not annually. Once Staff brought this to the attention of TEP, TEP indicated it would discontinue such annual filings. Staff believes this is appropriate.

Q. TEP has requested to be relieved of the requirement that it file a report every (5) five years listing potential improvements to Springerville Unit 4 that reduce emissions and costs associated with the improvements as ordered by Decision No. 65347, dated November 1, 2002. Does Staff believe TEP should be granted this request?

A. TEP stated this filing should not be necessary as Unit 4 is an unregulated, non-jurisdictional asset. Staff's analysis revealed that in Decision No. 65347, at Finding of Fact No. 66, the requirement described was for Units 1 and 2, not 4. In response to a Staff Data Request, TEP stated the request for elimination of this report should have been for Units 1 and 2. Staff then queried TEP as to whether or not the reason stated in the original request remained the same or if that reason had changed. TEP responded that: "Since the adoption of Decision No. 65347 (November 1, 2002), there has been substantial activity at the federal level regarding various emission standards, including the adoption of the Clean Power Plan. As a result, there is increased scrutiny of coal-fired power plant emissions at the federal level. Preparing the report is a costly endeavor". In addition, TEP now has an Environmental Compliance Adjustor through which for the Commission can track and review certain environmental compliance investments by TEP each year. Staff agrees that the requirement to file a report every five years, pursuant to Decision No. 65347, is no longer needed.

Q. TEP has requested to be relieved of the requirement that it file an Annual Cost Containment Report required initially by Decision No. 59594, dated March 29, 1996. Does Staff believe TEP should be granted this request?

A. Yes. TEP states the prudency of TEP costs is reviewed by the Commission in rate cases. Since TEP has had some rate cases since Decision No. 59594, the Annual Cost Containment Report is no longer needed.

Q. TEP has requested to be relieved of the requirement that it file an Annual Estimated First or Final Bill Report as required by Decision No. 64180, dated October 30, 2001. Does Staff believe TEP should be granted this request?

A. No. TEP states that this compliance requirement involves tracking a waiver of A.A.C. R14-2-210 which has been in place for years without incident and has been reported as part of the Commission's Electric Competition Rules reporting requirements. In Decision No. 64180, TEP was granted a waiver from A.A.C. R14-2-210-(A)(5)(b) and (c) which, respectively, state that a utility or billing entity may not render a bill based on estimated usage if the bill would be the customer's first or final bill for service or the customer is a direct-access customer requiring load data. Contingent on receiving these waivers, TEP was ordered to file an Annual Estimated First or Final Bill Report indicating the number of customers who received a bill based on estimated reads of this nature along with the reason why an actual read could not be obtained. Staff believes TEP wants to keep these waivers so, as a result, does not recommend granting this TEP request.

Q. TEP has requested to be relieved of the requirement that it file a Full Decoupling Report in connection with its Lost Fixed Cost Recovery ("LFCR") annual adjustment as required by Decision No. 73912, dated June 27, 2013. Does Staff believe TEP should be granted this request?

A. TEP states that the Commission has approved a partial decoupling mechanism for TEP (the LFCR), should consider information related to full decoupling and other rate design issues in a rate case at which time TEP can then provide the information, and the current requirement is unnecessary and increases workload for TEP. Staff is generally in support of this request. If TEP has no intention of asking for full decoupling, Staff recommends the Commission eliminate this reporting requirement for TEP.

Q. TEP has requested to be relieved of the requirement that it file an Annual Letter of TEP's Code of Conduct as required by Decision No. 62767, dated August 2, 2000. Does Staff believe TEP should be granted this request?

A. Yes. TEP states this requirement was related to electric competition and has been superseded by TEP's new Code of Conduct, which was approved in Decision No. 75033, dated April 23, 2015. Decision No. 75033 approved a UNS Energy Corporation Code of Conduct. This Code of Conduct is applicable to the affiliates of UNS Energy Corporation, one of which is TEP. Finding of Fact No. 1 indicates this approved Code of Conduct "updates UNS Energy's previously approved Code of Conduct". As this updated Code of Conduct does not include Reporting Requirements, it is reasonable to conclude the Reporting Requirement requiring TEP to file an Annual Report listing all "Extraordinary Circumstances excusing TEP's compliance" with the Code of Conduct approved by Decision No. 62767 is no longer in effect.

Q. TEP has requested to be relieved of the requirement that it file an Annual Summer Preparedness Report for the Cyprus Sierrita substation Certificate of Environmental Compatibility ("CEC") as required by Decision No. 69680, dated June 28, 2007. Does Staff believe TEP should be granted this request?

A. Yes. In Decision No. 69680, TEP was ordered to submit annually a summer preparedness report that documented the ability of TEP's Green Valley area 46 kV system to timely restore service to all customers served from the Green Valley substation and Canoa Ranch Substation following outage of the 138 kV South to the Green Valley line outage (Condition 4(a)). This condition was to remain in effect until a new 138 kV transmission line built by TEP from South Substation to Cyprus Sierrita Substation with an interim interconnection at Green Valley Substation become operational. On June 27, 2013, in Docket No. L-00000C-95-0084, TEP filed a Notice of Completion of Certificated Project in which it stated that the construction of the 138 kV transmission line had been completed in its entirety and energized as of June 25, 2013. Staff believes that given the construction of the line has been completed, the reporting requirement is no longer in effect and TEP's relief request in this instance should be granted.

Q. TEP has requested to be relieved of the requirement that it file an Annual Sign Replacement Report for the Cyprus Sierrita substation CEC as required by Decision No. 69680, dated June 28, 2007. Does Staff believe TEP should be granted this request?

A. Yes. In Decision No. 69680, TEP was ordered to submit annually a Sign Placement report that documented the location of signs in public rights-of-way giving notice of the construction of the 138 kV transmission line built by TEP from South Substation to Cyprus Sierrita Substation in what was referred to as the "Phase Two" corridor in the CEC. On June 27, 2013, in Docket No. L-00000C-95-0084, TEP filed a Notice of Completion of

Certificated Project in which it stated that the construction of the 138 kV transmission line had been completed in its entirety and energized as of June 25, 2013. Staff believes that given the construction of the line has been completed, the reporting requirement is no longer needed and TEP's relief request in this instance should be granted.

Q. TEP has requested that UNS Electric, Inc. be relieved of the requirement that it file an Annual Self-Certification Letter identifying progress made with the conditions set out in the CEC for the Vail substation to the Valencia substation as required by Decision No. 71282. Does Staff believe TEP should be granted this request?

A. No. As this requirement pertains to UNS Electric, not TEP, Staff believes this request should be made by UNS Electric.

Q. TEP has requested to be relieved of the requirement that it file an Annual Self-Certification Letter identifying which conditions have been met in the CEC authorizing construction of a double circuit, 345 kV transmission line running from TEP's South 345 kV Substation to a proposed TEP Gateway Substation in Nogales, Arizona in Santa Cruz County with a 115 kV interconnection to the 115 kV Valencia Substation and 345 kV line to the international border as required by Decision No. 64536, dated January 15, 2002. Does Staff believe TEP should be granted this request?

A. Yes. In Decision No. 73625, dated December 12, 2011, issued in response to the Seventh Biennial Transmission Assessment, the Staff recommendation to suspend efforts to upgrade the reliability to a continuity of service and new transmission construction for Santa Cruz County due to the high cost of capital upgrades was adopted in the ordering language. Therefore, TEP's relief request in this instance should be granted.

Q. TEP has requested that it be relieved of the requirement to develop a data base of existing renewable energy resources within its service area within six months from the effective date (June 1, 1994) of Decision No. 58643, revise it annually and submit to Staff each year as part of the historical data filings required under Integrated Resource Planning ("IRP") rules (R14-2-703 (A) and (B)). Does Staff believe TEP should be granted this request?

A. Yes. TEP states that this requirement is moot as it derives from a 1993 Decision based on the previous version of the IRP rules which were subsequently suspended and then superseded in 2010. Additionally, similar information is being provided in accordance with current IRP rules. TEP's Renewable Energy Resources are detailed in its most recent IRP Plan filing, dated April 1, 2014, in Docket No. E-00000V-13-0070.

SUMMARY OF RECOMMENDATIONS

Q. What are Staff's Recommendations in the testimony presented here?

A. Regarding TEP's proposed Prepay Metering Program, Staff recommends the following:

- The Program be approved as a Pilot Program for at least twenty-four months.
- The Program exclude customers relying on an electrical device for medical survival.
- The Program not be included in TEP's Energy Efficiency portfolio.
- TEP receive a waiver from providing a written disconnect notice as required under R14-2-211(D) for the purposes of this Program.
- TEP Lifeline customers be allowed to participate in the Program.
- TEP modify its Prepay Service Agreement in accordance with Staff's recommendations and file it with Staff for analysis, review and approval prior to the implementation of the Program.
- The rates and charges may need to be revised, pending Staff review.

Regarding TEP's request to be relieved of certain compliance requirements, Staff recommends the following:

- The following Retail Electric Competition Rules be suspended until further order of the Commission:
  - Systems Benefit Charge Filing (R14-2-1608 (A))
  - Annual Electric Competition Filing (R14-2-1613 (A) and (B))
  - Annual Consumer Information Label (R14-2-1617 (A), (C), (D) and (G))
  - Annual Disclosure Report (R14-2-1617 (G) and (E))

- TEP continue to file an Annual Update to its Electric Load Curtailment Plan as required by Decision No. 66034.

- TEP be relieved of the requirement that it file a report every (5) five years listing potential improvements to Springerville Units 1 and 2 that reduce emissions and costs associated with the improvements as ordered by Decision No. 65347, dated November 1, 2002.

- TEP be relieved of the requirement that it file an Annual Cost Containment Report required initially by Decision No. 59594.

- TEP continue to file an Annual Estimated First or Final Bill Report as required by Decision No. 64180.

- TEP be relieved of the requirement that it file a Full Decoupling Report in connection with its LFCR annual adjustment as required by Decision No. 73912.

- TEP be relieved of the requirement that it file an Annual Letter of TEP's Code of Conduct as required by Decision No. 62767.

- TEP be relieved of the requirement that it file an Annual Summer Preparedness Report for the Cyprus Sierrita substation CEC as required by Decision No. 69680.

- TEP be relieved of the requirement that it file an Annual Sign Replacement Report for the Cyprus Sierrita substation CEC as required by Decision No. 69680.

- UNS Electric not be relieved of the requirement that it file an Annual Self-Certification Letter identifying progress made with the conditions set out in the CEC for the Vail substation to the Valencia substation as required by Decision No. 71282.

- TEP be relieved of the requirement that it file an Annual Self-Certification Letter identifying which conditions have been met in the CEC authorizing construction of a double circuit, 345 kV transmission line running from TEP's South 345 kV Substation to a proposed TEP Gateway Substation in Nogales, Arizona in Santa Cruz County with a 115 kV interconnection to the 115 kV Valencia Substation and 345 kV line to the international border as required by Decision No. 64536.

- TEP be relieved of the requirement to develop a data base of existing renewable energy resources within its service area within six months from the effective date (June 1, 1994) of Decision No. 58643, revise it annually and submit to Staff each year as part of the historical data filings required under IRP rules (R14-2-703 (A) and (B)).

Q. Does this conclude Staff's direct testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT

RATE DESIGN

TESTIMONY

OF

ERIC VAN EPPS

EXECUTIVE CONSULTANT

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 24, 2016

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TUCSON ELECTRIC POWER COMPANY
DOCKET NOS. E-01933A-15-0322 ET AL.

This testimony addresses the proposed Rate Design Recommendations for the Environmental Compliance Adjustor ("ECA"), Demand-side Management ("DSM"), and Renewable Energy Standard and Tariff ("REST") adjustors.

Tucson Electric Power Company ("TEP") has proposed changes to its ECA and DSM adjustors. For its ECA, TEP has requested an increase in the cap from 0.25 percent of prior test-year annual revenues to 0.50 percent of annual revenues year-over-year. TEP has also requested to convert the collection of the ECA from an energy-based charge to a percent-based charge.

For its DSM adjustor, TEP is also requesting a change to the way the adjustor is collected, from an energy-based charge to a percentage-based charge.

Staff's rate design recommendations are summarized below:

1. Staff recommends that in TEP's next DSM Plan, TEP reassess its billing charge so that all customers, both residential and non-residential are billed based on an energy-based charge.

2. Staff recommends that the Company update its DSM Plan of Administration ("POA") so that it is consistent with all existing decisions.

3. Staff recommends that the Company file a POA for its REST adjustor consistent with the POA filed for UNS Electric, Inc. Staff further recommends that the POA incorporate all existing pertinent Commission decisions.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Eric Van Epps. I am an Executive Consultant employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant.

A. As an Executive Consultant, I provide recommendations to the Commission on matters involving electric and gas utilities. I also perform studies on ancillary issues pertaining to matters concerning the electric industry.

Q. Please describe your educational background and professional experience.

A. I have a bachelor's degree in Business Administration and Political Science, specializing in international business and international politics from Arizona State University. I also graduated with a degree in Sustainability with a focus on alternative energy and resources from Arizona State University. I have been employed with the Commission since January of 2013.

Q. Have you previously filed testimony in this docket?

A. Yes, I previously provided direct testimony addressing pro-forma adjustments for the Environmental Compliance Adjustor ("ECA"), Demand-side Management ("DSM") and Renewable Energy Standard and Tariff ("REST") for Tucson Electric Power Company. ("TEP" or "Company"). This rate design testimony addresses other aspects of the adjustors.

Q. Have you reviewed the testimony submitted by the Company in this case?

A. Yes. I reviewed the testimony of Company witness, Mr. Craig A. Jones, specifically regarding adjustments to the ECA and DSM adjustors. Mr. Jones is proposing a change to the way both adjustors are collected; the proposal would change the collection of the adjustors from a per kWh charge to a percentage charge. Additionally, the Company is requesting that the cap on the ECA be increased to allow the Company to more quickly recover costs associated with environmental compliance projects.

ENVIRONMENTAL COMPLIANCE ADJUSTOR

Q. What is the ECA?

A. The ECA is an adjustor mechanism that allows the Company to recover capital project carrying costs and incremental O&M costs related to environmental investments made by TEP and not already included in rate base or recovered through another Commission approved adjustment.

Q. Has the Company requested any changes to the ECA in this case?

A. Yes. The Company is requesting to increase the ECA cap from 0.25 percent of prior test-year annual revenues to 0.50 percent of annual revenues year-over-year, as well as convert the collection of the ECA from an energy-based charge to a percent-based charge.

Q. Does Staff have any concerns with the proposed year-over-year cap?

A. Yes. Staff feels that the Company did not fully explain how a year-over-year cap would function with regard to the ECA, further Staff does not believe the Company adequately explained why a year-over-year cap in necessary for the ECA. Staff would appreciate more evidence in the record to indicate just how this year-over-year cap would operate and what if any effect it would have on the prospective rate payer.

Q. Does Staff believe there is any justification for increasing the current cap on the ECA?

A. Yes. Currently the Company's ECA adjustor charge is at the cap, which is $0.00025 per kWh. The Company's ECA will reset to zero at the conclusion of this case; however, given the Company's aging coal fleet and the uncertainty with many environmental regulations currently before the federal government, it is conceivable that TEP could see an influx of environmental compliance capital costs after the rate case. Many of these environmental capital projects are quite costly and may very quickly increase the ECA from zero back to the cap of $0.00025 per kWh. The Company has indicated that going forward, it expects eligible carrying costs related to environmental compliance to be at, or above, $4,000,000 per year. Under the current cap the Company could recover, through the ECA, roughly $2,000,000 in capital carrying costs per year based on Total Company Retail Sales.

Q. Does Staff believe it is reasonable to increase the cap for the ECA?

A. Yes. Staff believes that costs associated with environmental compliance are typically in the best interest of the rate payer and for the most part are unavoidable due to federal mandates. Staff believes that the Company should be able to recover costs associated with these environmental compliance projects and believes it's reasonable to increase the cap to $0.00050 per kWh. This increase in the Cap would allow the Company to recover roughly $4,000,000 in capital carrying costs annually, based on Total Company Retail Sales. Which is consistent with the Company's expected eligible carrying costs of $4 million.

Q. Did the Company provide justification for why the ECA should be converted from an energy-based charge to a percent-based charge?

A. No.

Q. Does Staff have a position on percent-based charges vs. energy-based charges?

A. Yes. Staff believes that there are positive and negative aspects associated with both recovery methodologies; however, Staff currently favors energy-based charges. Staff believes energy-based charges are more transparent. Under a percent-based charge, collections would fluctuate based on ancillary rate changes (i.e. changes to adjustors, taxes, base rates, etc.). With an energy-based charge what you see is what you get, there are essentially only two variables, the kWh charge and the kWh sales volumes, and because there are fewer variables collections are more easily predicted and tracked throughout the year.

Q. Does Staff accept the Company's proposal to convert the charge associated with the ECA to a percent-based charge?

A. No.

Q. Did the Company provide a revised Plan of Administration ("POA") for the ECA in this case?

A. Yes. The proposed ECA POA in this case is Exhibit CAJ-6.

Q. Does Staff accept the changes to the ECA POA provided in Exhibit CAJ-6?

A. No. Currently, there is misunderstanding between Staff and the Company as to which POA for the ECA is in fact the current POA. Staff will be working with the Company to determine which POA provides the appropriate template to work from.

Q. Are there any other items associated with the ECA that you wish to address?

A. No.

DEMAND-SIDE MANAGEMENT

Q. What is the DSM Adjustor?

A. The DSM adjustor is an adjustor which allows the Company to collect monies associated with its Energy Efficiency program and budget.

Q. Has the Company requested any changes to the DSM Adjustor in this case?

A. Yes, the Company has requested a change to the way the adjustor is billed. The Company is proposing to apply the charge as a percentage-based adjustment to all classes with an effective date of its next DSM filing.

Q. Are there currently any customer classes receiving a percentage-based charge for the DSM adjustor?

A. Yes, pursuant to Decision No. 73912, June 27, 2013, the DSM Surcharge rate for non-residential customers is a percent of the total bill (before RES, LFCR, assessments and taxes).

Q. Does Staff have a position on percent-based charges vs. energy-based charges?

A. Yes. Staff currently favors energy-based charges. Staff believes energy-based charges are more transparent. Under a percent-based charge, collections would fluctuate based on ancillary rate changes (i.e. changes to adjustors, taxes, base rates, etc.). Further, under a percent-based charge there could be some segments of the customer base that are disproportionally charged.

Q. Why are non-residential customers in TEP's service territory currently billed a percentage-based charge while residential customers are billed an energy-based charge?

A. As part of the settlement agreement in the 2012 rate case, parties agreed to sign on as signatories as long as it was agreed upon that non-residential customers would be charged a percentage-based charge for DSM rather than an energy-based charge.

Q. Does Staff support billing non-residential customers a percentage-based charge?

A. No. Staff believes that when a percentage-based charge is applied broadly to all non-residential customers, small general service customers are unduly burdened.

Q. What is Staff's recommendation for the DSM adjustor charge?

A. Staff recommends that in TEP's next DSM Plan, TEP reassess its billing charge so that all customers, both residential and non-residential are billed based on an energy-based charge.

Q. Does Staff have any other DSM recommendations?

A. Yes. Staff recommends that the Company update its DSM POA so that it is consistent with all existing Commission decisions.

RENEWABLE ENERGY STANDARD AND TARIFF

Q. Has the Company requested any changes to its REST adjustor?

A. No.

Q. Does the Company have a POA for its REST Adjustor?

A. No.

Q. Does Staff have any recommendations pertaining to the REST Adjustor?

A. Yes, Staff recommends that the Company file a POA for its REST adjustor consistent with the POA filed for UNS Electric, Inc. Staff further recommends that the POA incorporate all existing pertinent Commission decisions.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize Staff's rate design recommendations.

A. Staff's rate design recommendations are summarized below:

1. Staff recommends that in TEP's next DSM Plan, TEP reassess its billing charge so that all customers, both residential and non-residential, are billed based on an energy-based charge.

2. Staff recommends that the Company update its DSM POA so that it is consistent with all existing Commission decisions.

3. Staff recommends that the Company file a POA for its REST adjustor consistent with the POA filed for UNS Electric, Inc. Staff further recommends that the POA incorporate all existing pertinent Commission decisions.

Q. Does this conclude your direct Rate Design testimony?

A. Yes, it does.